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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy And Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004)
Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities.	Rulemaking 04-04-025 (Filed April 22, 2004)

OPENING COMMENTS OF THE COGENERATION ASSOCIATION OF CALIFORNIA AND THE ENERGY PRODUCERS AND USERS COALITION ON THE PROPOSED DECISION OF ADMINISTRATIVE LAW JUDGE HALLIGAN

Michael Alcantar
Alcantar & Kahl LLP
1300 SW Fifth Avenue
Suite 1750
Portland, OR 97201
503.402.9900 office
503.402.8882 fax
mpa@a-klaw.com

Counsel to the Cogeneration Association of California

Evelyn Kahl
Rod Aoki
Nora Sheriff
Alcantar & Kahl LLP
120 Montgomery Street
Suite 2200
San Francisco, CA 94104
415.421.4143 office
415.989.1263 fax
ek@a-klaw.com
nes@a-klaw.com
rsa@a-klaw.com

Counsel to the Energy Producers and Users Coalition

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I. INTRODUCTION

This Proposed Decision, approaching four years in the making, represents a positive step toward pragmatic solutions for a prospective Qualifying Facility (QF) program. It does not, however, present a complete solution. The Proposed Decision (PD) leaves all parties, utilities and QFs alike, with an array of specific, unresolved questions and seemingly conflicting directives.[1] Implementation of the PD without modification will not achieve the Commission's dual policy objectives of retaining existing and encouraging the development of new Combined Heat and Power (CHP) resources for California's power supply portfolio. The Commission's final decision can be strengthened by addressing these concerns.

[1] These opening comments are submitted on behalf of the Cogeneration Association of California (CAC) and the Energy Producers and Users Coalition (EPUC) (collectively, CAC/EPUC) pursuant to Article 14 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission).

By any measure, this is a watershed decision for California's long and successful cogeneration program. In some measure the Proposed Decision provides the necessary positive and supportive provisions for a successful QF program. Yet in other measures it lacks requisite precision and specific resolution of key implementation issues. These issues can be addressed effectively through a clear and specific final decision. There are, however, detailed issues that may be best suited for a moderated meet and confer process. Regardless of the process, a summary of four broad priority areas and key issues of concern are:

1. Price – (a) setting an energy price floor that reflects actual operating gas fired generating unit heat rates (physical heat rates of real units as opposed to an administratively determined, artificial heat rate range utilizing an SCE-employee-designated volatility "collar" of ± 2,000 Btu/kWh); (b) recognizing and addressing vague and uncertain price calculation issues; and (c) establishing fixed pricing options consistent with the Market Price Referent "all in price" contemplated by the Proposed Decision.[2]

2. Standard offer contract – (a) establishing specific standards (as opposed to simply a vague EEI contract shell) for non-price terms and conditions for must-take QF resources that are non-discriminatory; i.e., at least equal to utility-owned procured resource provisions, and specifically provide for the pass through of future "regulatory legal risk conditions" (e.g., Greenhouse Gas costs, regulatory compliance required capital additions, Electric Reliability Organization costs); (b) making a specific finding that all QF resources acquired under the prospective QF program per se constitute ratepayer benefits to pre-empt counter-productive utility challenges to such contracts; and (c) assuring that pricing terms are predictable and secure for the entire term of any contract and not subject to unraveling by MRTU, federal Energy Policy Act 2005 implementation or other regulatory changes.

3. New and "Small" CHP QF Resources – (a) establishing an annual threshold, similar to the TURN proposal, under which a CHP resource may sell its excess power to the utility under a standard offer contract, eliminating the "need assessment" for these resources; (b) for new CHP resources that do not clear the annual threshold, refining the proposed procedures for addressing "need assessments" to ensure

[2] CAC/EPUC acknowledge and appreciate the apparent effort of the PD to establish an all in price of 7.4¢/kWh as consistent with the CAC/EPUC proposal in this proceeding; of course what must be addressed is the fact that the PD's 7.4¢/kWh differs markedly from CAC/EPUC's 7.4¢/kWh.

their reasonable application and (c) clarify that these new resources retain their right to interconnection under state-jurisdictional Rule 21.

4. Implementation of the Complete Prospective QF Program – (a) expressly precluding any piecemeal implementation of the Prospective QF Program so that QFs have all features of the program (capacity pricing options, energy pricing options, complete and available contract terms and conditions); and (b) eliminating potential gaming that imposes dramatically lower energy pricing while delaying the availability of the long term firm contract option.

Comments on Proposed Decisions are typically by design critical of factual, policy or legal issues that warrant change. In this highly challenging proceeding there are features of the Prospective QF Program to acknowledge as positive, supportive and essential for any successful future QF policy. For example:

- The establishment of a default standard offer requirement for As-Available and Firm operations is pivotal for a CHP program to be successful and to overcome the inability to reasonably negotiate bilateral contract terms (PD pp. 2, 116-117).

- The partial reliance on the Market Price Referent (MPR) for full term contract capacity pricing is a positive first step in establishing realistic capacity pricing for gas fired CHP resources (PD pp. 3, 93).

- The apparent adoption of a traditional utility “must take” obligation for CHP baseload power maintains a critical component for the success of the California cogeneration program (PD p. 87).

- The apparent effort to identify and sustain a reasonably robust “all in” price for CHP resources under certain presumed market conditions is a positive attribute of the Proposed Decision (PD p. 92 and Table 7).

- The apparent retention of the utilities’ traditional role to serve as Scheduling Coordinator for all QF power deliveries and utility insular interface with the California Independent System Operator (CAISO) for QF resources (PD p. 87).

- The clear resolution of critical commercial issues for the standard offer contracts related to credit requirements (PD p. 117).

The PD’s positive steps, if coordinated with modifications proposed in these comments, will ensure a successful California QF policy.

As for process a workshop might be considered the best means to address implementation and standard offer contract development issues, but CAC/EPUC have some reservations. CAC/EPUC have maintained longstanding requests for expedited and emergency action on long term QF contract issues for good reason. CAC/EPUC existing facilities have already faced or are soon facing contract terminations and an uncertain future; potential new CAC/EPUC projects are languishing and withering under the same lack of clarity. Time is of the essence for these facilities, but so is clarity over identified implementation issues as well as the establishment of a standard offer contract. Carefully considering the balance of issues CAC/EPUC urge the Commission to immediately vacate the dates for the utility filings of a proposed standard offer contract and substitute the following directives:

- If implementation issues remain unresolved in the final decision the Assigned Commissioner shall convene a workshop to begin no later than 14 days from the final decision. The implementation workshop is to be a strictly monitored process with the Assigned Commissioner presiding over issues identified and left unresolved by the final decision.

- All parties may file proposed standard offer contract forms no later than June 7, 2007, with reply comments on the proposals no later than June 21, 2007. If there are unresolved issues pertaining to the standard offers, provide that those issues may be addressed at the post-final decision workshop on implementation issues. Alternatively, if the issues have been sufficiently addressed in written comments the Assigned Commissioner should issue a ruling on the provisions of the standard offer contract no later than 21 days after the conclusion of the Assigned Commissioner's workshop following the final decision.

- Direct that an Assigned Commissioner's Ruling on any outstanding implementation or standard offer contract issues will be issued no later than 21 days after the conclusion of the Assigned Commissioner's workshop following the final decision.

Concerns, but more importantly, pragmatic solutions in the following sections are divided into "Substantive Policy Issues," "Technical Implementation Issues" and "Legal Issues."

II. ARGUMENT

A. Substantive Policy Issues

1. Pricing Under the Commission's Prospective QF Program Needs Careful Scrutiny and Revision

a. The Energy Price Must Contain an Appropriate "Cap and Floor."

At page 30, the PD states, "*SCE's Proposed SRAC energy formula is derived from a twelve-month rolling average of historical Day-Ahead market price data with a "collar" around the possible IER values to provide a cap and floor for possible IER values*." According to SCE, during the period from August 2002 through July 2005, the implied market heat rates in SP15 fell within the range of 5,864 and 9,864 and therefore SCE recommended that these "collars" be adopted by the Commission.

There are two fundamental problems with this 5,864 to 9,864 Btu/kWh "collar". First, neither the cap nor the floor values are reflective of operational unit heat rates for any physically operating natural gas fired generating resources. Prices derived from these artificially chosen heat rates fail to support existing or enhance new long term investment. There is no assurance to a lender or investor that the SCE Market Index Formula will, over the long-term, provide stable revenues commensurate with the quality of power delivered and the associated investment risk. SCE asserts its "collar" is intended to "mute volatility." Indeed it can be said to mute volatility to the extent that it unrealistically and artificially chooses heat rate values that do not reflect the realities of operating gas fired generators. Moreover, SCE has doubled its "muting" effect by also employing a rolling 12 month average calculation of the applicable heat rate. This feature alone sufficiently mutes volatility. The imposition of both SCE muting methodologies makes the heat rates so muted as to be unrealistic. In essence SCE's arbitrary and artificial collar methodology does nothing to enhance long-term investment, and should be modified.

The cap and floor should be established in a manner consistent with real operating resource heat rates. These resources would set appropriate IER value boundaries and ideally would be represented by a real world Combustion Turbine (CT) and real world Combined Cycle Gas Turbine (CCGT). For example, TURN advocated in its testimony a heat rate "cap" tied to a CT (including adjustments for startup). The TURN heat rate calculation seemed low, but produced results in excess of 10,000 Btu/kWh. This CT value offers the basis for a rationally established cap. For the establishment of a floor heat rate an appropriate example of a real world operating CCGT is SCE's Mountainview facility. Given operating characteristics and normal heat rate degradation the optimal Mountainview heat rate is certainly no lower than 7,000 Btu/kWh. These two resources reflect real world, operational cap and floor heat rate values, respectively, for the Market Heat Rate component of the Market Index Formula. Accordingly, the decision should be modified to adopt a CT based cap of 10,000 Btu/kWh and a floor of 7,000 Btu/kWh.

Second, the use of the 5,864 to 9,864 collar recommended in the SCE testimony is incorrect since it is not calculated in the manner adopted by the PD to establish the Market Heat Rate under the MIF methodology. In SCE's calculation of the average IER around which the arbitrary 2,000 Btu/kWh collar would be applied, SCE first removed an O&M value from the market price. The Commission's proposed MIF methodology rejected SCE's calculation regarding the removal of an O&M value from the market price. Accordingly, with the O&M value included, the average IER for the period August 2002 to July 2005 is 8,238 Btu/kWh. If the artificial 2,000 Btu/kWh collar is applied to this corrected value, the properly calculated cap would be 10,238 Btu/kWh and the floor would be 6,238 Btu/kWh. At a minimum, the decision should adjust the "collar" values consistent with the adopted MIF methodology, but the most appropriate modification would be to reflect real operating generation heat rates. It is essential that the Commission carefully evaluate and establish the cap and floor heat rates in order to sustain the Prospective QF Program.

b. An Option for a Firm and Fixed 7.4¢/kWh "All In" Price Should be Offered to QFs.

CAC/EPUC acknowledge the apparent effort of the PD to demonstrate that the "all in" price proposal for LRAC was matched by the PD's "all in" price. (See Table 7). Unfortunately there are dramatic and material differences in CAC's 7.4¢/kWh and the PD's 7.4¢/kWh.

The difference is found in the fixed and secure aspects of the CAC/EPUC recommendation, and the highly speculative set of assumptions that must be employed to reach the same price under the PD. CAC/EPUC's 7.4 cents/kWh represents an energy price based on a fixed heat rate and a firm capacity price. The PD's 7.4¢/kWh, while containing positive elements, is only attained at assumed gas prices and an assumed MIF IER of 7,903. Both the gas price and the MIF IER are subject to significant changes over the period of a long-term contract.

If, as hoped, the Commission wants to provide QFs with pricing options that would provide predictable and firm revenue streams, the Commission should establish an option for QFs akin to the CAC/EPUC proposal reflected on Table 7. Some QFs may prefer certainty of MPR capacity and fixed IER and O&M recovery. Others may prefer the potential revenue available under the PD's MIF pricing option. The Commission should allow QFs to elect an LRAC firm pricing option that reflects current MPR values for capacity, a fixed heat rate of 7,500 Btu/kWh and an established O&M adder for the term of the contract.

2. Specificity Regarding the Terms and Conditions that May or May Not be Included in the Standard Offer Contract is Necessary

Pursuant to the PD the utilities will submit a proposed "simplified version of the Edison Electric Institute Master Agreement will be the basis for our prospective QF Program contract options." The problem with this simple directive is that the EEI Form is simply a template from which parties are able to select and incorporate specific terms and conditions. Absent greater specificity over the terms and conditions that should or should not be in the EEI form, the Commission leaves the parties in a contentious vacuum.

a. QFs Must Be Allowed To Pass Through Appropriate Regulatory Costs Just As The Utilities Are Allowed To Do.

The Prospective QF Program provides compensation for both energy and capacity, but the MPR pricing used for these prices is based solely on the installation and variable operating costs of a CT. The costs do not reflect so called regulatory legal risk costs, or other operation costs that are now or will in the future be imposed. Resources on the utilities' system, including utility-owned resources such as SCE's Mountainview facility, incur costs for reliability compliance and environmental compliance. Compliance with these requirements, which continue to evolve, can constitute significant costs to any generator or cogenerator. Utility owned resources are allowed to pass these costs through to ratepayers, yet this same treatment is not specified or addressed in the PD.

Like SCE's Mountainview or PG&E's Contra Costa 8 pass through provisions, QFs should be allowed to pass through appropriate regulatory and environmental costs, particularly where such costs are in excess of the costs reflected in the MPR. Such costs would include: (a) taxes or charges associated with carbon emissions; (b) capital additions for regulatory environmental compliance; and, (c) the costs of compliance with Federal Energy Regulatory Commission (FERC) mandated reliability requirements imposed by NERC, the WECC and the CAISO. None of these costs are reflected in the MPR based pricing that the Commission has used for its Prospective QF Program.

In order for the parties to implement the Commission's Prospective QF Program in a timely and efficient manner, the Commission must provide direction to the parties on critical issues such as the appropriate pass through of regulatory and environmental costs as discussed above.[3]

b. Contract Pricing and Non-Price Terms Should Be Maintained for the Full Term of the Agreement.

Page 62 of the PD states in pertinent part as follows:

> *Finally, while we find that a MIF based on Day-Ahead prices best reflects the utilities' avoided cost, we expect that a further update will be required when the CAISO's MRTU is operational, at which point the CAISO's day-ahead market will likely be the appropriate benchmark for pricing SRAC energy.*

Contracts under the Commission's Prospective QF Program must not be subject to reopening or unilateral change. QFs will necessarily rely on these agreements, and the unraveling of these agreements with new, speculative and uncertain pricing conditions renders the contracts illusory. The PD does recognize that capacity payments will be sustained for the life of the contract, but the same features should be applied to other

[3] Another issue which warrants greater direction from the Commission on contract terms is the imposition of capacity payment penalties for failure to deliver 95% of the contract power during on-peak months and 90% of the contract power during off-peak months (PD at 91). The most compelling issue in this regard is the appropriate time period for the measurement of deliveries, and it is strongly suggested that the Commission establish a monthly based period for such deliveries, consistent with traditional QF operations.

payment conditions. Parties to the contract must be able to rely upon the whole of their bargain to set their operational expectations, as well as to be able to appropriately seek and secure financing. Financing is predicated on adequate, secure and certain revenue streams from the underlying contract terms.

The Commission should establish that a Prospective QF Program contract is secure with a known price for the full term of the contract. The pricing must not be subject to unanticipated or unpredictable changes based on the status of MRTU, the implementation of EPAct 2005 or other regulatory risks.[4] It is through price certainty that the Commission can meet its goals to retain existing QF resources and encourage new resources. Once a contract is signed, the Commission should respect the sanctity of the parties' bargain and assure predictability of contract terms, not intervene to change discrete contractual elements.

c. Capacity Delivery under the Standard Offer Should Not Be Inappropriately Limited Consistent with State Law.

The Commission should assure that the Standard Offer allows for increases to the capacity under a standard offer contract and compensation for that capacity if the increase is accomplished in the normal course of business. The definition of normal course of business for such increases in capacity has already been codified under state law (See California Public Utilities Code § 371). The Commission's Prospective QF Program should be modified to expressly permit increases in contractual capacity to the extent that such increases are consistent with Section 371.

3. The PD Does Not Provide <u>New</u> CHP QF Resources With Any Realistic Means of Obtaining a Contract With a Utility.

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[4] Since the MRTU schedule calls for implementation in February 2008, the PD, unless modified, will have the legacy of taking almost four years to establish a contract pricing methodology that lasts two years. This is hardly reflective of a long term QF contract policy.

In Decision 04-01-050, the Commission voiced its expectation that "*new QFs will be able to obtain a contract to provide power to an IOU without having to participate in a competitive procurement process, and without having to negotiate an individual bilateral contract.*" (D.04-01-050 at 160) The PD attempts to implement this expectation through the following option for new QFs:

> *New QFs may seek a contract under the Prospective QF Program. However, if an IOU claims a new QF contract will result in over-subscription, the IOU shall meet and confer with its Procurement Review Group (PRG) within 20 days of receiving such a request from a new QF. The Commission's Energy Division will prepare a brief summary of the PRG meeting regarding the IOU's ability to enter into the new QF contract. If the PRG feedback is unfavorable toward the new QF, the new QF may opt to file a formal complaint with the Commission.* (PD at 3).

This option, however, is not consistent with the Commission's expectation for new QFs contained in D.04-01-050 for the following reasons. First, CAC/EPUC are not aware of any utility seeking new QF resources, in any proceeding, in the recent past.[5] There has been no public announcement that any new base load QF has been successful in bidding into a utility procurement solicitation. Moreover, neither PG&E nor SCE forecast <u>any</u> new installations of QF cogeneration resources in their current long-term procurement plan filings. (See PG&E LTPP at IV-21, Volume I; see also SCE LTPP at 17, Volume 1B) Importantly, CAC/EPUC have not been able to explore the utilities' position on QF need because they have been banned from access to essential utility resource data.

Second, while the PD has changed the role of the PRG, it is unclear whether giving the PRG more authority will provide a real option for new QFs. The PRG is currently only an advisory body, with no real decision-making authority. Under the PD, the PRG would

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[5] Indeed it would appear that any solicitations for QF power have been only to blunt challenges of utility failures to meet mandatory PURPA obligations as opposed to good faith solicitations of QF power.

have a responsibility to decide the fate of new QFs. CAC/EPUC do not know at this time whether the utility's private vetting of its claim of oversubscription with its PRG provides any protection for a new QF. CAC/EPUC understand that the PRGs, as presently constituted, do not include representatives of the QF community. Moreover, some members of the PRG, such as the Coalition of California Utility Employees (CUE), may have an inherent bias against a utility entering into a contract with facilities which do not employ their constituents. In summary, CAC/EPUC are not aware of any member of the PRG that would be an advocate for a new QF resource; indeed, certain members of the PRG may be inclined not to favor new QF resources. Importantly, there is no opportunity for the QF to address the PRG directly.

Finally, and most critically, if the utility and the PRG deny the new QF a contract ("unfavorable feedback"), the PD places the burden on challenging a PRG determination against procurement with the QF. This is an option without effect. In recent history, QFs have not had any ability to view meaningful data about the IOU's resource needs, and it is not anticipated that QFs will have this ability in the future. Therefore, the QF will not be able to present any meaningful evidence of the utility's need in its complaint to the Commission and the complaint process is in effect procedure without substance. While the QF may have some access to data in the out years, given the fast moving procurement environment in California, this data is not sufficient either for supporting investment in new facilities or in proving unequivocally utility need for these resources.

A simple way to address this effective lack of an option for new QFs is to give some definition to what the term "oversubscription" means in the PD. The Commission should allow new QFs to obtain a contract under the Prospective QF Program where:

- New QFs would serve a specified percentage of the baseload portfolio that was historically served by CDWR contracts as those contracts expire or are terminated; or
- New QFs would serve load equivalent to or less than the percentage of load served by existing QFs multiplied by the new load growth.

Such definition is consistent with the Commission's determinations that (1) it does not want to see erosion of the utilities' QF supplies (PD at 118) and (2) it wants to "*ensure that QFs continue to have opportunities to provide power to the utilities*…" (PD at 20)

Finally, the Commission should provide an additional option for new, as available QFs based upon the proposal put forward by TURN as a small QF contract option. As discussed in the PD:

> *TURN also recommends that QF projects of 25 MW or less that consumes at least 25% of their power internally and sell all of their additional output to the utility should be eligible for longer-term contracts. (*PD at 123).

TURN's proposal makes good sense and good policy. A QF offering the utility a limited block of power of 25 MW or less is not the type of resource that will be engaged in large-scale utility RFOs. Moreover, requiring a QF with a small export quantity to jump the hurdles proposed in the PD for approval of new contracts is unreasonable in light of the quantity at issue. Finally, placing a quantity limit on new must-take exports substantially lessens the burden on the utilities of dramatic increases in new QF resources.

CAC/EPUC propose two minor modifications of the TURN proposal, however. While CAC/EPUC support the net 25 MW limit delivery to the utility, subject to the 25% on site use obligation, as a practical matter the limit should be stated as an annual GWh limitation. In other words, the limit should equal 25 MW x 8760 x .75 or 164.25 GWhs. This would allow a larger capacity unit to deliver for a shorter period of time within the GWh limitation. Anything above that quantity may be addressed through the PRG review process. Second, the requirement that the QF use 25% of its power internally should be applied to the increment of new capacity added. Consider the following example. An industrial facility has 99 MW of existing capacity serving 100% on-site load. To meet growing demand, the facility installs a new 40 MW generator, making immediate use of 10 MW to serve onsite load. In this case, the facility would be able to export a maximum of all of its excess power, up to an annual limit of 164.25 GWh on an annual basis.

Additionally, as discussed in more detail below, the Commission must ensure that it retains its jurisdiction, allowing new QF facilities to interconnect with the utility under Rule 21 when all of their output is sold to the interconnecting utility. FERC has made its policy clear that when a QF delivers its output to on-site load and/or to the interconnected utility under the Public Utilities Regulatory Policies Act of 1978, that interconnection falls within state jurisdiction. FERC has stated:

> *When an electric utility is obligated to interconnect under Section 292.303 of the Commission's Regulations, that is, when it purchases the QF's total output, the relevant state authority exercises authority over the interconnection and the allocation of interconnection costs. But when an electric utility interconnecting with a QF does not purchase all of the QF's output and instead transmits the QF power in interstate commerce, the Commission exercises jurisdiction over the rates, terms, and conditions affecting or related to such service, such as interconnections.*

Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures, 104 FERC ¶61,103, at ¶813. The Commission should affirm this directive to the utilities in this decision to avoid further dispute regarding QF interconnection consistent with this finding.

4. The Commission's Prospective QF Program Must Be Implemented as a Coherent Whole.

The PD contains a number of key determinations on prices to be paid for QF energy and capacity, both as-available and firm, and adopts standard offer contracts which incorporate the PD's pricing provisions. The PD sets time frames for service of, and comments on, draft standard offer contracts, but does not specify a timeframe for availability of the contracts. The PD also orders the utilities to revise their short-run avoided cost pricing calculations consistent with the decision, but does not specify an implementation date for the price change.

In order to meet the Commission's expectation that "*as old QF contracts expire, new or renewed contracts will replace them*" (PD at 118), pricing provisions and standard offer contracts must be implemented at the same time. Absent this clarification, it is possible that existing QFs will be subject to revisions in contract pricing before any of the alternatives which the Commission provided in its Prospective QF Program become effective. This result would be directly contrary to the Commissions' clear directive that *"[w]e do not want to see erosion of the utilities' QF supplies…*." (Id.)

As an example of the risks of piecemeal implementation, assume that the Commission decided that the revised pricing terms described in the PD be implemented immediately upon issuance of the Commission's final decision. In contrast, implementation of the Prospective QF Program would be delayed to frame standard offer contracts. The PD provides 45 days for the utilities to submit draft contracts, 21 days thereafter for parties to submit comments, and some undetermined length of time for workshops, mediation and/or hearings to ensue. Under such a circumstance, existing QFs, though theoretically eligible for long run avoided cost (LRAC) pricing options under the Prospective QF Program, would be subject to revised downward pricing. The QF would be immediately confronted with the operational consequences associated with a pricing revision without the option of seeking an alternative, yet-to-be-established LRAC contract. While the Prospective QF Program in theory provides the QF with a Commission-sanctioned alternative, this option would not actually be available to the QF if revised pricing is adopted before the new standard offer contracts are available. Availability of the contract options must necessarily include the establishment of the standard offer terms, the execution, approval by the Commission and implementation of the new contract.

Finally, a non-cohesive implementation of policy and pricing could provide unfortunate incentives for the successful initiation of the Prospective QF Program. If there is an interim period during which QFs are denied access to contractual and pricing terms commensurate with firm power deliveries, or compelled to modify operations, unfair advantage could be taken. During this period there may not be any strong impetus for some to expeditiously develop the contractual and pricing alternatives provided by the Prospective QF Program. Contemporaneous implementation of all aspects of Prospective QF Program and the PD's revised pricing would provide the appropriate balance for all parties.

Revisions to QF Pricing and other features of the Prospective QF Program are inextricably linked and must be implemented together. Failure to do so will result in unintended and potentially severe consequences adverse to stated Commission policy. The Commission should clarify that implementation of revised pricing under the PD will not go into force and effect until the Commission's Prospective QF Program, and each of the options under that Program, are in place and available to existing QFs.

5. The Commission Should Not Relinquish State Jurisdiction over QF Resources and Impose CAISO Tariff Obligations.

At page 130, the PD determines that: (1) QFs of one MW or greater should be required to comply with the CAISO tariffs; and (2) QFs should serve as their own scheduling coordinators, with the option of purchasing these services from the utility. Both of these determinations require clarification. They are at best inconsistent with the required must take obligations for QF power reflected in the PD.

The PD appropriately cites to a key determination in the Energy Action Plan II on the issue of the applicability of CAISO tariffs to QFs:

> *On this issue, we are guided by Key Action Item 7 of Section 4 of EAP II, which provides: "Adopt a long-term policy for existing and new qualifying facility resources, including better integration of these resources into CAISO tariffs and deliverability standards."* PD at 129.

But other provisions of EAPII lead to contrary conclusions. Key Action Item 2 provides *"for the continued operation of cost-effective and environmentally sound existing generation needed to meet current reliability needs, including combined heat and power generation.*" Key Action Item 9 provides "*[d]evelop tariffs and remove barriers to encourage the development of environmentally-sound combined heat and power resources and distributed generation projects*." Read in context, the intent of the EAPII is to promote QF resources and restrict CAISO tariffs from impairing the unique operating characteristics of cogeneration resources. There is no basis to conclude that QF resources are to comply with CAISO tariffs regardless of whether such tariffs apply.

The PD provides that <u>the CAISO "*will have to accept [QF Power] as must-take*</u> *and focus on refining and shaping IOU power portfolios through the use of other resource options*." (Emphasis added. PD at 87) Clearly, in adopting the Energy Action Plan, the

Commission and the Energy Commission did not intend to relinquish state jurisdiction, not did they intend to subject QFs, regardless of size, to the whole of the CAISO tariff regardless of applicability. This would include in particular any attempt by the CAISO or the IOUs to submit QFs to inapplicable and problematic generator agreements or unnecessary interconnection processes.[6] EAPII should be read to call for the elimination of CAISO tariff provisions which serve as barriers to QFs. The Commission is uniquely situated to accomplish that end by retaining Rule 21 interconnection oversight of the California cogeneration program.

Similarly, the PD's imposition of scheduling coordinator obligations on QFs is inconsistent with EAPII. Scheduling coordinator obligations, particularly for QFs offering relatively small amounts of power (e.g., under 25 MW) represent a barrier to both existing and new QF operations. Must-take power should be scheduled by the QFs' existing scheduling coordinator, in most cases the interconnected utility. The IOUs are in the best position to balance load and resources across their systems and avoid penalties which would otherwise be incurred by QFs. If a QF elects to purchase utility scheduling coordinator services (as opposed to electing third party services from another), the PD makes clear that such services should be priced at the utility's incremental cost of providing those services. The PD should require utilities to post the incremental charges for these services as part of the implementation process for the Prospective QF Program.

6. Locational Benefits Are Not Captured When Using A Proxy Resource And Should Be Consistent With Utility Payments For These Benefits.

[6] *See, e.g.,* Order Rejecting Participating Generator Agreement and Meter Service Agreement, 101 FERC ¶61,081.

In its testimony CAC/EPUC raised the issue of locational benefits. The only mention of this issue is at pages 8-9, of the PD. The PD expresses a view that that QFs which offer certain benefits, including locational benefits, should be uniquely situated to compete in utility solicitations. But this observation does not address the reflection of these benefits in avoided cost payments. For QFs in or near load centers, locational benefits are not captured under the proxy resource used to determine LRAC. These benefits can include reduced line losses, improved voltage support and frequency regulation, black start capability, reduced investment in transmission and distribution, increased reliability or reduced need for reserves. It is appropriate to compensate the QFs for these types of benefits.

To illustrate the benefit local QF generation provides, consider SCE's reliability service rate filing submitted to FERC on June 28, 2005 (ER05-1154). This filing sought approval for $125 million in order to satisfy SCE local reliability needs. This total included reliability-must-run (RMR) service costs of $64 million which reflected the cost of having the necessary local generating units in place net of a market credit for the value of energy and capacity produced from these units. SCE RMR generation total was 2,060 MW. The RMR requirement represented an above market cost of $31/kW-year ($64 million/2,060 MW). Similarly, the Local Capacity Commitment costs are associated with additional local needs under ever increasing load levels. SCE has 1,220 MW of capacity to supply this requirement. As with the RMR cost, the almost $20 million for this need reflects a market revenue credit. These local resources represent a net cost of $16/kW-year ($19.8 million/1,220 MW). Having local QF generation in place reduces the need for resources such as the RMR and local capacity commitment generation. This in turn reduces the cost to all SCE ratepayers for providing reliable service. The Commission should take into account the local benefits provided by QFs in the LRAC determination as recommended in CAC/EPUC testimony.

B. Technical Implementation Issues

1. IOU TOU Factors Should Be Tied to IOU Tariff TOU Periods for Retail Ratemaking Until More Appropriate TOU Factors Can Be Determined.

At page 68 the PD notes that it is "*appropriate to update the TOU and TOD factors periodically*" and requires the IOUs to include TOU/TOD factors and periods utilized as part of their most recent RFOs. CAC/EPUC do not oppose reasonable updating of TOU factors. However, updates should be predictable, well in advance of operations and established over the minimum of a year. The PD would allow seemingly constant changes in the updated factors since multiple utility RFOs could be issued during the course of a year. TOU factors should promote the delivery of capacity and energy during periods expected to be beneficial to the ratepayers without imposing undue risk on the sustained operation of the QF. The PD acknowledges there is insufficient record evident to support a change at this time. (*Id*.) The Commission should favor stability in these factors and retain the TOU factors for QF payments as the same used for the utility TOU periods for retail ratemaking. The Commission should retain the TOU factors until such time as there is a review in a future proceeding.

2. The Commission Should Clarify The Method and Escalation Rates To Be Applied To The Adopted SRAC and LRAC Cost Components.

The Commission has adopted the TURN economic carrying charge presented in Exhibit 149, Appendix B, which requires an annual adjustment to reflect inflation. The PD adopted a 2004 first year CT capacity price of $60.94/kW-yr. The 2004 cost components comprising the $60.94/kW-yr CT capacity price must be escalated to 2007. Using the Consumer Price Index (CPI) to reflect the inflation adjustment, the 2007 annual CT cost is $66.92/kW-yr:

2007 Annual CT Cost to Reflect Inflation Adjustment					
Year	**Annual Average Percent Change In CPI**	**Real Fixed Charge[(a)] per kW**	**Insurance[(a)]**	**Fixed O&M[(b)]**	**Total CT Cost**
	(1)	(2)	(3)	(4)	(5)
2004		51.93	1.31	7.70	60.94
2005	2.66%	53.32	1.39	7.91	62.61
2006	3.39%	55.12	1.49	8.17	64.78
2007	3.23%	56.90	1.59	8.44	**66.92**

(a) $Cost_n = Cost_{n-1} \times (1 + Rate_n)$
(b) $Cost_n = [Cost_{n-1} \times (1 + Rate_n)] + .05$

Similarly the variable operation and maintenance (O&M) payment of $2.47/MWh must be escalated in the future. The Commission should clarify that this cost component is to be adjusted annually for inflation. Accordingly, for each year after 2007, the O&M adder should be adjusted by the annual average percent change in the CPI.

With respect to LRAC capacity payments, the PD states on page 93 that *"[t]he adopted method is similar to that proposed by IEP, but simply uses a short form of the more detailed MPR calculation of the annualized capacity payment* …" Specifically the PD notes on page 92 that: "*IEP states that it 'used the model adopted by the Commission to determine the MPR' to calculate its capacity price* (Testimony, p. 85)."[7]

The PD also states on page 85 that "[*p*]*ayments for firm, unit-contingent capacity will be based on the market price referent (MPR) capacity cost adopted in Resolution E-4049 of $980/kW, annualized over a 20-year term at a Weighted-Average Cost of Capital* (WACC) rate of 8.5%, which results in an annual amortized cost of $104/kW-year."

While correctly establishing the LRAC capacity payment on the MPR CCGT capacity costs, the PD incorrectly determines the MPR capacity costs through the employment of a "short form" of the MPR calculation. The "short form" result presented in Figure 2 on page 93 of the PD significantly understates how the MPR calculated the fixed cost components attributable to the CCGT. The "short form" only calculated the fixed cost components attributable to the "return" and "depreciation" fixed cost components. Accordingly, the $104/kW figure does not reflect the MPR fixed cost associated with: (1) income taxes, (2) property taxes, (3) fixed O&M, and (4) insurance costs. Indeed, the following table presents a comparison of the Resolution E-4049 adopted MPR fixed component (based on the Appendix A $/kWh prices and the adopted MPR capacity factor) with the PD "short form" calculation for a contract beginning 2007.

Description	Appendix A	Equivalent $/kW
MPR 10 year fixed component	$0.02269/kWh	$157[8]
PD "short form" MPR Capacity Costs	na	$104
MPR exceeds PD "short form" ($/kW)	na	$53
MPR exceeds PD "short form" (%)	na	50.1%

7 As presented in the testimony, the fixed costs of a combined-cycle gas turbine (CCGT) are comprised of the following fixed cost components: return (equity and debt), depreciation, income taxes, property taxes, fixed operation and maintenance (O&M) cost and insurance.

8 Calculated based on MPR 79% Capacity Factor as stated in Appendix E of Resolution E-4049 at line 15 (.02269 x 8760 x 0.79 = 157.02).

Accordingly, in the final decision, the Commission should clarify both the method and escalation rates to be applied to the adopted SRAC and LRAC cost components.

3. The Commission Should Eliminate SDG&E's Ancillary Services Credit Adjustment from the As-Available Capacity Payment Calculation.

At page 90, the PD adopts SDG&E's proposed ancillary services adjustment to the as-available capacity payment proposed by TURN. This adjustment is inconsistent with the Commission's adoption and application of TOU factors to SRAC capacity payments. The ancillary service adjustment is based upon SDG&E's testimony that it would realize some revenue from providing non-spinning reserves to the CAISO from the CT displaced by the QF. In other words, SDG&E assumes it can receive revenue from periods of time when the CT is not running to serve load. However, the SRAC payment method adopted by the Commission requires the QF to be "running" in order to be paid any capacity payment; therefore the fundamental premise underlying the Commission's adopted method is the assumption that the "avoided CT" is always operating at full capacity and unavailable to provide any Ancillary Services. In other words, the payment is structured such that a QF is able to receive the full CT avoided cost if it provides power 8,760 hours per year. The Commission should eliminate SDG&E's ancillary credit adjustment from the as-available capacity payment calculation.

4. The Calculation of IOU Burner Tip Gas Prices Must Be Clarified Consistent With Commission Precedent.

On page 65, the PD adopts a burner-tip gas price as the basis for calculating energy payments, determines that Topock is now a robust border point to replace the proxy pricing of Malin plus PG&E intrastate transportation. However there is a lack of specificity regarding the calculation of total burner tip prices for SCE and SDG&E and the precise requirements for PG&E related to the border price determination as between Malin and Topock. The PD should be modified as follows:

- SCE and SDG&E are to calculate a burner-tip gas price as the sum of: (1) the bid-week Topock CA border natural gas price in accordance with D.96-12-028; and (2) the intrastate natural gas transportation cost (including shrinkage, applicable federal, state and local surcharges, fees and taxes that would be applicable to the point of delivery).

- The PG&E burner-tip natural gas price is calculated as the sum of: (1) the simple average (*i.e.*, 50%/50% weighting) of the bid-week Malin and Topock CA Border natural gas prices in accordance with D.96-12-028; and (2) the intrastate natural gas transportation cost (including shrinkage, applicable federal, state and local surcharges, fees and taxes that would be applicable to the point of delivery).

C. Legal Issues and Reservation of Appellate Challenges and Positions

Pursuant to Rule 14.3, legal issues addressed in briefing will not be reargued here. CAC/EPUC simply note that PURPA and California Public Utilities Code §390(b) remain in full force and effect. PURPA requires must take power at avoided costs; avoided costs are clearly defined as the incremental costs which the utility would incur "but for" the purchases from QFs. 18 C.F.R. 292.101(6). There was no demonstration that the "market" proposed to be the utilities' avoided costs represents the utilities' respective incremental costs. Additionally, PU Code § 390(b) sets forth the clear calculation requirements for SRAC energy payments. The proposed MIF does not strictly meet these requirements. To the extent that the PD is inconsistent with these laws, CAC/EPUC reserve all rights to appeal.

1. The PD's Reliance on the Current Record, with its Absolute Ban on QF Parties' Access to Relevant Data without a Particularized Showing of Harm, Is Unlawful.

At pages 131-134, the PD discusses confidentiality, concluding:

> *there is no due process error involved in reaching a decision on the IOU's avoided cost and other issues on the current record, which is complete for this purpose*

Federal law requires that QFs be paid based upon the utilities' avoided cost and lists the utility data required to calculate avoided costs. 18 C.F.R. 292.302. The avoided cost is the last incremental purchase on the margin; this relevant information was not provided to the QF parties. Lack of access to information rendered the QFs unable to determine the actual utility avoided cost and present that position to the Commission. While the Commission may consider certain information confidential and may use confidential information in its proceedings, it is unlawful to conduct those proceedings with an absolute ban on access to relevant, material information. *See* D.06-06-066, modified by D.07-05-032, at 80 (COL 24)

D.06-06-066, as modified, holds that the burden is on the producing party, *i.e.* the IOU, to explain why a protective order would be inadequate in cases where IOUs fail to support their claim of confidentiality with a specific showing of harm. *Id.*, at 83 (OP 9) There was no showing of particularized harm that would result from disclosure of this information. *See, e.g.*, CAC/EPUC Response to SCE Supplemental Comments on AL 1832, dated August 15, 2005. This information should have been disclosed under a protective order.

III. CONCLUSION

For all of the foregoing reasons the Proposed Decision establishing the Prospective QF Program should be modified consistent with the issues raised in these comments.

Respectfully submitted, May 25, 2007

Michael Alcantar

Evelyn Kahl

APPENDIX

PROPOSED MODIFICATIONS (**Additions**, **~~deletions~~**)

Page 2

Specifically, we adopt:

- **The Market Index Formula (MIF),** which is an updated short-run avoided cost (SRAC) formula for pricing SRAC energy. The MIF is based on the formulistic method adopted in Decision (D.) 01-03-067 ~~Modified Transition Formula~~ but contains a market-based heat rate component, instead of an administratively determined incremental energy rate (IER);

***

Page 2-3

- **Prospective QF Program Contract Provisions**

  - SRAC Energy Payments: Market Index Formula (MIF). Existing QF contracts with energy pricing provisions specifically stating that the Commission determined ~~providing~~ SRAC is the basis for energy payment will also be priced pursuant to the MIF.

  - ~~o~~ Payments for As-Available Capacity: Based on the full fixed cost of a Combustion Turbine (CT) and the economic carrying charge as proposed by The Utility Reform Network (TURN)~~, less the estimated value of Ancillary Services (A/S) as generally proposed by San Diego Gas & Electric Company (SDG&E)~~.

Page 3

  - Payments for Firm Capacity: Based on the market price referent (MPR) capacity cost adopted in Resolution E-4049 of $980/kW, annualized over a 20-year term at a Weighted-Average Cost of Capital (WACC) rate of 8.5%,which results in an annual amortized cost of $104/kW-year.

***

An Entry Procedure for New QFs. New QFs may seek either of the aforementioned contracts as follows:

- New QFs may seek a standard contract under the Prospective QF Program just as existing QFs may. ~~However, if an IOU claims a new QF contract will result in over-subscription, the IOU shall meet and confer with its~~

~~Procurement Review Group (PRG) within 20 days of receiving such a request from a new QF. The Commission's Energy Division will prepare a brief summary of the PRG meeting regarding the IOU's ability to enter into the new QF contract. If the PRG feedback is unfavorable toward the new QF, the new QF may opt to file a formal compliant with the Commission.~~ The Commission will allow new QFs to obtain a standard contract under the Prospective QF Program where: (1) the new QF will serve a portion of the baseload portfolio that was historically served by CDWR contracts as those contracts expire or are terminated, and (2) the new QF will serve load equivalent to or less than the percentage of load served by existing QFs multiplied by new load growth.

- New, as available QFs may also receive a standard contract under the Prospective QF Program. Projects that are 219,000 GWh (25 MW X 8760) or less in size and that consume at least 25% of their power internally and sell all of their additional output to the utility are eligible for a contract. The 25% requirement includes any increments of new capacity added to the project.
- Where the new QF sells all of its output to the interconnected utility it's interconnection shall be governed by state Rule 21.

Page 4

Two recent developments limit the effect of this order ~~on energy prices and capacity prices over the next five years~~ because (1) a large number of QFs have entered into contractually based energy pricing agreements, and (2) many existing QFs are on contractually based capacity pricing.

Page 6

Accordingly for PG&E, SCE, and SDG&E, we define and adopt the Market Index Formula or "MIF" to calculate SRAC energy payments to QFs. The MIF equation employs the formulistic approach ~~is similar to the Modified Transition Formula~~ we adopted for SCE in D.01-03-067, with the exception that the market-based heat rate component, formerly the Incremental Energy Rate (IER), will be calculated from a 12-month rolling average of historical North of Path 15 (NP15) or South of Path 15 (SP15) Day-Ahead (DA) market price data with a "collar" around the possible IER values to provide a cap and a floor consistent with actual operational generation resource heat rate to mitigate excessive pricing uncertainty ~~volatility~~.

Page 7

However, we are persuaded that there are currently few options to utility purchases, particularly for Small QFs, whose size prevents them from participation in the CAISO markets. These QF should continue to have available standard offers, albeit at market-based prices.

Page 7-8

For these reasons, we adopt two flexible market-based contract options in addition to the competitive solicitation and bilateral contracting options already available to QFs. ~~To safeguard against oversubscription in the future, we adopt a process by which the utilities can request relief from the requirement to enter into the standard offers.~~ QF resources acquired under the prospective QF program per se benefit ratepayers.

First, QFs who choose only to provide non-firm, as-available power will have access to a one- to five-year as-available contract with energy prices based on the MIF formula and posted as-available capacity payments based on the full cost of a combustion turbine ~~less the estimated value of Ancillary Services~~.

Second, we will make available a one-to-ten-year contract for firm unit-contingent power, with energy prices based on the MIF formula, and capacity payments based on the market price referent (MPR) capacity cost adopted in Resolution E-4049 of $980/kW, annualized over a 20-year term at a Weighted Average Cost of Capital (WACC) rate of 8.5%, which results in an annual amortized cost of $104/kW-year. This longer-term contract option is intended to provide sufficient contract and pricing certainty to allow QFs to make decisions on capital expenditures for facilities and upgrades.

Page 9

We also continue to require the utilities to make available CAISO scheduling services to all QFs. ~~QFs whose size prevents them from participation in the CAISO markets should not have to establish scheduling operations staff to interact with the CAISO.~~

Page 53

PG&E further asserts that e~~E~~xisting resources in PG&E's portfolio (i.e., utility retained generation, CDWR, and those contractual obligations which allow economic dispatch) are regularly compared to the market price, with power being either bought or sold at that price. Regardless of the resource stack, according to PG&E, the utility's avoided cost for a given hour becomes the market price. The market price that PG&E contends that it uses to determine what resources are dispatched in northern California is the NP15 price. If the dispatch decision is made day-ahead, then the price is the day-ahead NP15 price. If the dispatch decision is made hour-ahead, then the price is the hour-ahead NP15 price. PG&E~~'s~~ states that its traders are active in the market and are keenly aware of current prices at which sellers are offering, buyers are bidding and the price at which the most recent transaction was executed. Price discovery is available through voice brokers, electronic trading platforms, such as the ICE, and direct contact with trading counterparties. (*Id.,* p. 3-10.)

Page 59-60

We agree that SRAC energy prices should reflect power prices as reported at the NP15 trading point for PG&E, and the SP15 trading point for SCE and SDG&E. Although the Day-Ahead market prices may not include all of the types of contracts that exist in the electricity industry today, these are the energy costs that ~~would otherwise be incurred by~~ the utilities incur in the short run~~ to replace QF power~~. QF parties contend that the NP15/SP15 prices are below utility avoided cost, yet the power products at NP15/SP15 are for firmer power products than the as-available energy provided by QFs.

Page 62

~~Finally, while we find that a MIF based on Day-Ahead prices best reflects the utilities' avoided cost, we expect that a further update will be required when the CAISO's MRTU is operational, at which point the CAISO's day-ahead market will likely be the appropriate benchmark for pricing SRAC energy~~.

Page 63

Given the uncertainty in formulating such estimates, all three utilities will now be on the MIF as described herein. With regard to our consistency goal in this avoided cost rulemaking, there is no compelling reason to not adopt the same variable O&M adder for all three utilities. As SDG&E notes in its direct testimony, the Commission has adopted variable O&M figures for other purposes:

> SDG&E proposes the variable O&M component be based on the variable O&M of a Combined Cycle Gas Turbine (CCGT). This level of variable O&M is consistent with the type of power that would replace QF power, baseloaded power supplies as provided by a CCGT. In the decision in phase 1 of this proceeding, D.05-04-024, the Commission recommended using the data developed in R.04-04-026 for the costs of operating a CCGT. For consistency, SDG&E proposes to use the 2004 value for the variable cost of a CCGT adopted in Phase 1. (Exhibit 85.)

We concur with the ~~this~~ approach of relying on the Market Price Referent CCGT variable O&M component and adopt it for use in the SRAC energy formulae for the three utilities.

Page 68

As noted above, the Legislature did not adopt a specific formula, nor did it adopt specific TOUs factors. Therefore, it is appropriate to update the TOU or TOD factors periodically. The evidence in this proceeding clearly demonstrates that the TOU/TOD data is outdated. Unfortunately, the parties recommending specific changes to the TOU/TOD factors and periods did not provide a sufficient showing to support their recommendations. ~~Nevertheless, we believe that updating the IOUs TOU/TOD factors~~

~~and periods to be consistent with the TOU factors adopted in other procurement proceedings is reasonable and will require the IOUs to include the TOU/TOD factors and periods utilized as part of their most recent RFOs.~~ Therefore, we will ~~We also~~ require the IOUs to provide updated TOU/TOD factors and periods when they file their next long-term procurement plans for approval.

Page 85-86

Today, we adopt two contract options for expiring or expired QF contracts and new QFs – Our Prospective QF Program. The first option is a one- to five-year as-available power contract. The second is a one- to ten-year firm, unit-contingent power contract. Payments for as-available capacity will be based on the fixed cost of a Combustion Turbine (CT) as proposed by The Utility Reform Network (TURN)~~, less the estimated value of Ancillary Services (A/S) as generally proposed by San Diego Gas & Electric Company (SDG&E)~~. Payments for firm, unit-contingent capacity will be based on the market price referent MPR) capacity cost adopted in Resolution E-4049 of $980/kW, annualized over a 20-year term at a Weighted-Average Cost of Capital (WACC) rate of 8.5%,which results in an annual amortized cost of $104/kW-year.

Page 88

Once a full CT capacity value is determined, adjustments to that value may ~~should~~ be considered. For example, ~~we agree that~~ the value of additional (ancillary services) revenue streams associated with the physical ownership of an actual CT may ~~should~~ be accounted for in our estimate of capacity value. In its rebuttal testimony, CCC recommended the use of the full cost of a CT as the avoided value of as-delivered capacity, but also acknowledged that an adjustment to as-delivered capacity prices would be warranted given certain substantial evidence. (Exhibit 103, pp. 59-60.) CCC explored TURN's evaluation of the potential for such an adjustment based on an assessment of energy profits where an adjustment hinged on an accurate estimate of the number of hours of annual CT operation.

Page 89 - 90

We agree with TURN, SCE, and SDG&E that the avoided CT annual cost should be based on an economic carrying charge rate, escalated for inflation over the life of the contract. Using a levelized nominal dollar value to compute the CT annual cost would ~~overstate the avoided capacity cost as well as~~ present additional cost and risk for utilities and ratepayers. A primary concern is that the use of a levelized nominal value would require higher capacity payments in early years, exposing the utilities and their ratepayers to the risk of nonperformance if the QF went off-line or simply failed to perform. While termination penalties or the posting of security could mitigate some of the concern, calculating a CT cost based on an economic carrying charge rate and escalating for inflation would eliminate this concern. In addition, as pointed out by SCE and TURN, it would be inappropriate to use a 20-year levelized value for a contract of less than 20 years in length. Using an economic carrying charge rate, escalated for inflation over the life of the contract, allows us to provide more flexibility in contract terms, from one year up to five years with the same CT cost estimate. ~~As-available capacity prices should be expressed in real dollars.~~

Page 90

For the as-available contract option, we adopt the CT cost and ~~real~~ economic carrying charge rate calculations proposed by TURN as presented in Exhibit 149, Appendix B~~, with an ancillary services adjustment subtracted from the adopted value as suggested by SDG&E. The estimated ancillary services value proposed by SDG&E is an annual average value; however, we believe this is an over-estimate and should be adjusted downward to reflect the fact that SDG&E's value of $14.82/kW-year is more indicative of a peak value. Accordingly, we reduce it by two-thirds to $4.94/kW-year~~. Based on the assumptions presented in Exhibit 149, Appendix B, TURN calculates a total marginal CT cost of $64.13/kW-year in 2006. ~~Using the adopted TURN value for $64.13, the resulting capacity value would be $59.19/kW-year ($64.13/kW-year - $4.94/kW-year).~~

Page 93

Figure 2 Simple Interest Annual Payment for Capacity Given the Baseload MPR Capacity Price				
$/kW	**Rate %**	**years**	**$/kW-year**	**E-4049, Appendix E 2006 MPR Non-Gas Inputs**
$ 980.00	7.13%	20	$93	Cost of Long-Term Debt is 7.13%
$**9**80.00	8.5%	20	$104	WACC: Weighted-Average Cost of Capital = (Cost of Equity x Equity %) + (Cost of Debt x (1-tax rate) x Debt %)
$ 980.00	12.78%	20	$138	The Cost of Equity is 12.78% in the latest MPR Resolution E-4049

Page 95

The QF Parties recommend that the Commission should provide the following options to QFs with expiring contracts and new QFs: (1) A QF could choose to be paid SRAC and as-available capacity payments (similar to the existing SO1 contracts); (2) If the QF is willing to enter into a PPA of at least 10 years but no more than 20 years, the QF should receive a PPA based on the all-in cost of a new combined cycle power plant, using updated assumptions and the Commission's MPR pricing model; and (3) negotiated agreements. ~~CAC/EPUC and~~ CCC also recommend that the Commission adopt, as a goal, a cogeneration portfolio standard. The cogeneration portfolio standard would require the utilities to continue to make available long-term standard offer contracts until they achieve a 25% increase in the amount of cogeneration in California over and above January 1, 2005 levels by the end of 2010.

Page 112

We agree with TURN in part, that what the IOUs "avoid" by purchasing QF energy is the price that they would otherwise pay ~~in the wholesale market~~ for replacement energy. ~~Thus, f~~For purpose of determining short-run energy payment to QF in this proceeding, we find that the SRAC price should reflect the Day-Ahead market prices. For longer-term contracts, the IOUs generally avoid procurement of baseload capacity. We find that, aside from the QF contract options presented in this order, the price should be the result of a competitive process.

Page 116 - 117

First, for existing QFs, the utilities shall offer new one- to five-year, as-available standard offer contracts to QFs. The contracts shall be updated to require compliance with CAISO tariffs, including the Resource Adequacy (RA) tariff, to the extent those tariffs are applicable to the QF. However, QFs with expiring contracts seeking to sign new, one- to five-year as-available contract shall not be required to provide new credit support provisions nor new interconnection studies.

Page 117

QFs under the one- to five-year as-available contracts shall receive SRAC energy payments as discussed herein along with the as-available capacity payment described herein. Future standard ~~New~~ contracts will be subject to any changes in capacity payments resulting from future modifications to the RA counting rules, however, no existing contracts will ~~not~~ be affected. The utilities ~~QFs larger than one megawatt in dependable capacity~~ will be responsible for scheduling coordination with the CAISO, however, QFs have the option of acting as their own scheduling coordinators. To the extent the utility is not acting as the scheduling coordinator, it must offer scheduling coordinator services to the QF ~~the utilities must provide that service~~ for a reasonable cost. We adopt PG&E's recommendation to use the EEI Master Contract as a starting point for new standard QF contracts, as described herein.

Second, the utilities will offer a one- to ten-year contract term to those QFs with expiring contracts that are willing to provide unit firm capacity and that desire a longer-term contract. As with the as-available contracts, QFs under the one- to ten-year fixed capacity contracts will receive the revised SRAC energy payments as discussed herein. Long-term firm capacity payments will be based on the MPR capacity cost of $980/kW adopted in Resolution E-4049 which results in an annual cost of $104/kW-year. The higher capacity payments associated with the firm capacity contracts will appropriately compensate the QFs for the increased hedge value of assuring firm capacity for a longer term. These contracts will only be available to those QFs willing to offer unit-firm capacity. Locational benefits, if provided by these QFs, will also be compensated. The all-in payments, excluding the QF-specific locational benefits, associated with the two prospective QF Program options are shown in Table 4a, attached to this order, at an illustrative gas price. QFs may also elect an LRAC firm pricing option consistent with CAC/EPUC's recommendation summarized in Table 7 for the term of the contract.

Page 117

We adopt PG&E's recommendation to use the EEI Master Contract as a starting point for new QF contracts, as described herein. Non-price terms and conditions under our Prospective QF Program must be non-discriminatory; i.e., at least equal to utility-owned procured resource provisions. Accordingly, standard offer contracts under the Prospective QF Program shall specifically provide for the pass through of future "regulatory legal risk conditions" (e.g., Greenhouse Gas costs, regulatory compliance required capital additions, Electric Reliability Organization costs.

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The new standard contracts will also have updated performance requirements to reflect the firm capacity, but QFs with expiring contracts seeking to sign new unit-firm contracts shall not have to provide additional credit support, nor should they be required to perform additional interconnection studies. The utilities will continue to be ~~QFs larger than one megawatt are~~ responsible for scheduling coordination, although the QF has the option to act as its own scheduling coordinator. To the extent the utility does not act as a scheduling coordinator, it ~~utilities~~ must offer scheduling service to QFs at a reasonable cost. QFs who are not able to offer unit firm capacity will be able to either continue on a one- to five-year as-available contract from year to year or may participate in utility resource solicitations and bilateral negotiations.

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… we expect that as old QF contracts expire, new or renewed QF contracts will replace them. All QF resources acquired under the prospective QF program constitute per se ratepayer benefits. Also, increases in QF contractual capacity that are consistent with increases permitted by Public Utilities Code § 371 will be accommodated by the standard contracts in the prospective QF program.

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A ~~If a~~ new QF may have ~~seeks~~ access to ~~one of~~ the standard contract options described above just as an existing QF has.~~, and the IOU contends it would be inconsistent with the existing need determination from the Long-Term Procurement Plan (LTPP) proceeding, the utility must consult with its Procurement Review Group (PRG) within 20 days of receiving a contract request from a QF. The PRG consultation period shall be initiated within 20 days of receiving a contract offer from a QF. If a QF believes that a contract is being unreasonably withheld, it may file a complaint with the Commission.~~ The Commission will allow new QFs to obtain a standard contract under the Prospective QF Program where: (1) the new QF will serve a portion of the baseload portfolio that was historically served by CDWR contracts as those contracts expire or are terminated, and (2) the new QF will serve load equivalent to or less than the percentage of load served by existing QFs multiplied by new load growth. New, as available QFs may also receive a contract under the Prospective QF Program. Projects that export 164,250 MWh (25 MW X 8760 X 0.75) or less and consume at least 25% of their power internally and sell all of their additional output to the utility are eligible for a contract. The 25% requirement includes any increments of new capacity added to the project. Where the new QF sells all of its output to the interconnected utility it's interconnection shall be governed by state Rule 21. Utilities and QFs will also have the opportunity to address the need for new contracts as part of the utilities' long-term procurement plan filings in R.06-02-013 or its successor.

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Furthermore, requiring the utilities to make available one to ten-year unit firm capacity contracts, as well as optional one- to five-year as-available contracts is consistent with and supports one of the key actions in the EAP II. ~~Our prospective QF Program process will ensure that the amount of QF power under contract is consistent with the utilities' need. If a utility currently does not need additional QF power, for example, the utility is only required to renew existing contracts if it chooses, and will not be required to purchase new QF capacity if the utility can demonstrate that it no longer needs capacity.~~

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We find that QFs should generally be required to comply with applicable CAISO tariff requirements, however, as recommended by the CAISO and SDG&E, we do not expect existing QFs to be required to complete new interconnection studies. As observed by several parties, neither the CAISO nor the utilities have described what type of disruption would be caused by retaining QFs' existing arrangements, and in fact, CCC points out that the Kern River Cogeneration Company (KRCC) contract would extend KRCC's existing interconnection agreements for the term of that contract, five years. The current "CAISO exempt" and "must-take" status of the QF contracts stems from the fact that the CAISO did not exist when the contracts were signed. New contracts must explicitly take the existence of the CAISO and its tariff requirements into account. We reject ~~adopt~~ PG&E's recommendation that QFs one MW or greater should be required to comply with the CAISO tariffs. We also reject ~~adopt~~ PG&E's recommendation that QFs serve as their own scheduling coordinators. The CAISO must accept QF power as a "must-take" resource and QFs greater than one MW should only be required to comply with CAISO Tariff provisions to the extent the provisions are directly applicable to QF operations. Moreover, t~~T~~he utility should continue to serve as the scheduling coordinator for QFs, however, the QF should have ~~has~~ the option of serving as its own scheduling coordinator. The QF has the ~~, with the~~ option of purchasing these services from the utility at cost.

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The Assigned Commissioner may convene a workshop to begin no later than 14 days from the final decision's mailing date to address implementation issues left unresolved by the final decision. Interested parties shall file proposed standard offer contract forms no later than June 7, 2007, with reply comments on the proposals no later than June 21, 2007. If there are unresolved issues pertaining to the standard offers provide that those issues may be addressed at the post-final decision workshop on implementation issues. Alternatively, if the issues have been sufficiently addressed in written comments the Assigned Commissioner should issue a ruling on the provisions of the standard offer contract no later than 21 days after the conclusion of the Assigned Commissioner's workshop following the final decision. An Assigned Commissioner's Ruling on any outstanding implementation or standard offer contract issues will be issued no later than 21 days after the conclusion of the Assigned Commissioner's workshop following the final decision. ~~The respondent IOUs will have 45 days from the effective date of this decision within which to file and serve their draft standard offer contracts There will be a comment period following the filing of the compliance contracts~~. The pricing determinations in this decision will not become effective until final standard offer contracts are available to QFs as discussed in this decision.

PROPOSED MODIFICATIONS TO FOF AND COL

Findings of Fact

~~8. It is neither reasonable nor practical to base short-run avoided costs on a "QF-out" or "aggregate value" pricing methodology because the continuing long-term obligations to thousands of megawatts of QF power mean that QF power cannot be "out".~~

~~9~~. 8. The Transition Formula was intended as a temporary measure, to be used to calculate SRAC energy payments until energy payments could be based on PX market-clearing prices pursuant to § 390(c).

~~10~~. 9. The PX is no longer operational.

~~11~~. 10. SRAC energy payments under the Transition Formula have exceeded market prices, and potentially avoided costs, on occasion.

~~12. Given the amount of QF generation currently under contract to the IOUs, an energy price that is based on an assumption that a large block of that generation has disappeared is not reasonable.~~

~~13~~. 11. Each of the utilities has demonstrated that market prices play a key role in achieving least cost dispatch.

~~14.~~ 12. SRAC energy prices should reflect power prices consistent with the utilities' avoided costs. ~~as reported the NP 15 trading point for PG&E and the SP 15 for SCE and SDGE.~~

~~15.~~ 13. PG&E's energy pricing proposal links the SRAC energy prices to day-ahead trading points, but would require formal Commission updates immediately and on an ongoing basis.

~~16.~~ 14. SDG&E's energy pricing proposal is ~~consistent with § 390 (b) and~~ linked to market prices.

~~17.~~ 15. SCE's energy pricing proposal is preferable to SDG&E's because it uses a twelve-month rolling average of historical market prices as opposed to a two-year average, resulting in SRAC energy prices that reflect more current market prices. SCE's method of calculating SRAC is reasonable. SCE uses a twelve-month rolling index of historical Day-Ahead market prices in lieu of pre-1996 Incremental Energy Rate (IER) values. This method yields a SRAC that more closely reflects the short-run resources the utility currently ~~would~~ purchases~~ in the absence of QF generation~~.

~~18.~~ 16. A Market Index Formula based on day-ahead market prices best reflects the utilities' short-run energy purchases~~avoided cost~~.

~~19~~. 17. There is no compelling reason not to adopt the same variable O&M adder for all three utilities.

~~20.~~ 18. With regard to avoided cost, whether the utility bought the gas to run its own plant, or bought the power from a merchant plant fueled by natural gas, burner-tip gas would be required.

~~21~~. 19. The Legislature did not adopt a specific formula or specific factors for use in implementing § 390(b).

~~22~~. 20. It is reasonable to update the TOU factors used to calculate SRAC ~~to be~~ consistent with TOU factors adopted in future ~~other~~ Commission proceedings.

~~23~~. 21. The MIF is based in part on day-ahead market prices, but is not a direct market price proxy as envisioned in D.01-01-007.

~~24~~. 22. Pursuant to D.04-10-035, QF as-available capacity currently "counts" for purposes of meeting RA requirements.

~~25~~. 23. The firmness of bilateral power may vary by trade, whereas the power products traded on ICE are clearly defined. Power contracts traded on ICE are liquidated damages (LD) contracts that are not unit contingent.

~~26~~. 24. Power indices are also published for the long-term forward market where power is sold by the month, quarter, and year. These forward prices, along with day-ahead power, represent firm power products priced on an all-in basis, with no separate capacity payment. Delivery is certain and subject to recourse.

~~27~~. 25. NP15/SP15 day-ahead contracts are ~~significantly~~ firmer than QF as-available power contracts which have no penalties for non-delivery, no forecasting requirements, no performance requirements, and a unilateral right to terminate on 30-days notice.

~~28~~. 26. As-available power priced using NP15/SP15 implied market heat rates will provide a clear, market-based default contract for QFs that do not opt to provide power under one of the unit-firm contract options, negotiated bilaterals, or as-bid in an IOU power solicitation.

~~29~~. 27. Using a levelized nominal dollar value to compute the CT cost would ~~overstate the avoided capacity cost as well as~~ present additional cost and risk for utilities and ratepayers.

~~30~~. 28. Using an economic carrying charge rate, escalated for inflation over the life of the contract, allows us to provide more flexibility in contract terms, from one year up to ten years with the same CT cost estimate.

~~31~~. 29. For purposes of calculating payments for as-available capacity, it is reasonable to adopt the full CT cost and ~~real~~ economic carrying charge rate calculations proposed by TURN as presented in Exhibit 149, Appendix B~~, with an ancillary services adjustment subtracted from the adopted value as suggested by SDG&E~~.

~~32~~. 30. It is not reasonable to reduce CT annual capacity cost by the estimated ancillary services value proposed by SDG&E~~ by two-thirds to reflect the fact that SDG&E's value is an annual average value and ancillary services needs occur primarily in peak periods. Accordingly, we reduce SDG&E's suggested ancillary services value by two-thirds to $4.94/kW-year~~.

~~33.~~ 31. A simplified version of the Edison Electric Institute Master Agreement will be the basis for our prospective QF Program contract options. The simplified version should contain, at a minimum, the contract features presented in Table 1 of this decision.

~~34. Potential over-subscription due to new QF contracts can be evaluated, first, through and IOU's Procurement Review Group (PRG) within 20 days of receiving such a request from a new QF. The Commission's Energy Division can prepare a brief summary of the PRG meeting regarding the IOU's ability to enter into the new QF contract. If the PRG feedback is unfavorable toward the new QF, the new QF may opt to file a formal compliant with the Commission~~

34. A new QF may have access to the standard contract options provided by the Prospective QF Program just as an existing QF has. The Commission will allow new QFs to obtain a contract under the Prospective QF Program where: (1) the new QF will serve a portion of the baseload portfolio that was historically served by CDWR contracts as those contracts expire or are terminated, and (2) the new QF will serve load equivalent to or less than the percentage of load served by existing QFs multiplied by new load growth. New, as available QFs may also receive a contract under the Prospective QF Program. Projects that export 164,250 MWh (25 MW X 8760 X 0.75) or less and consume at least 25% of their power internally and sell all of their additional output to the utility are eligible for a contract. The 25% requirement includes any increments of new capacity added to the project. Where the new QF sells all of its output to the interconnected utility it's interconnection shall be governed by state Rule 21.

~~35.~~ 33. Long-term QF policy choices will continue to affect ratepayers for 10 to 20 years.

~~36.~~ 34. It is reasonable to extend our prospective QF Program contract options to QFs that are, or were, on contract extensions approved in D.02-08-071, D.03-12-062, D.04-01-050, and D.05-12-009.

35. QF resources acquired under the prospective QF program per se constitute ratepayer benefit.

36. Pricing terms must be predictable and secure for the entire term of any contract.

37. It is reasonable that our Prospective QF Program should accommodate increases in contractual capacity to the extent that such increases are consistent with Section 371 of the Public Utilities Code.

38. It is reasonable for the Commission to take into account the local benefits provided by QFs in the LRAC determination.

Conclusions of Law

1. Pursuant to Pub. Util. Code § 390(b), SRAC energy payments shall be based on a Transition Formula until the requirements of § 390(c) are met.

2. As set forth in PURPA, avoided costs are the cost of energy, which, in the absence of QF generation, the utility would otherwise generate itself or purchase from another source.

~~3. No right, contract term, or fair market expectation exists that the Commission must adopt the QF-in/QF-out approach to developing short-run avoided costs.~~

~~4. The variable factor formulation of the Transition Formula, as established in D.01-03-067, and updates to the formula are legal and permitted by § 390(b).~~

~~5.~~ 3. The Commission should assure ~~adjust the factors in the Transition Formula such~~ that the SRAC energy prices ~~resulting from the formula continue to~~ accurately reflect the utilities' avoided costs.

~~6.~~ 4. Separate capacity payments should generally only be made for unit-contingent power products that are either dispatchable, or that are significantly firmer than the non-unit contingent, Liquidated Damages (LD) contracts (i) bought and sold at NP15/SP15, and/or (ii) scheduled for phase-out for Resource Adequacy (RA) purposes, per D.06-10-035.

~~7.~~ 5. The Unit-Firm one-to-ten year QF contracts should count toward RA requirements because these contracts are unit-contingent contracts with performance obligations and recourse for non-delivery.

~~8.~~ 6. Payments to QFs under PURPA must reflect the avoided cost of the utility purchasing the energy and capacity.

~~9. Failure to consider utility resource needs in our long-term QF policy options would prevent us from achieving our goal of environmentally-sensitive, least-cost electric service.~~

~~10.~~ 7. IOUs should modify their monthly SRAC energy prices using the MIF adopted in this order. No pricing determinations under this decision shall go into effect until the Commission has approved the Prospective QF Program's standard offer contracts and those contracts are available to QFs.

~~11~~. 8. IOUs should post the monthly SRAC energy prices and annual capacity prices on their websites and file the prices with the Commission's Energy Division and DRA.

~~12.~~ 9. PURPA does not require that the Commission make available long-term standard offer contracts.

~~13.~~ 10. A solicitation process wherein the IOUs would issue requests for offers from QF generators to meet specific, identified resource needs, ~~is~~ may be insufficient to meet the must purchase obligations in PURPA.

~~14. Potential over-subscription due to new QF contracts should be evaluated, first, through and IOU’s Procurement Review Group (PRG) within 20 days of receiving such a request from a new QF. The Commission's Energy Division should prepare a brief summary of the PRG meeting regarding the IOU's ability to enter into the new QF contract. If the PRG feedback is unfavorable toward the new QF, the new QF may opt to file a formal compliant with the Commission.~~

11. A new QF may have access to the standard contract options provided by the Prospective QF Program just as an existing QF has. The Commission will allow new QFs to obtain a contract under the Prospective QF Program where: (1) the new QF will serve a portion of the baseload portfolio that was historically served by CDWR contracts as those contracts expire or are terminated, and (2) the new QF will serve load equivalent to or less than the percentage of load served by existing QFs multiplied by new load growth. New, as available QFs may also receive a contract under the Prospective QF Program. Projects that export 164,250 MWh (25 MW X 8760 X 0.75) or less and consume at least 25% of their power internally and sell all of their additional output to the utility are eligible for a contract. The 25% requirement includes any increments of new capacity added to the project. Where the new QF sells all of its output to the interconnected utility it’s interconnection shall be governed by state Rule 21.

12. Non-price terms and conditions under our Prospective QF Program must be non-discriminatory; i.e., at least equal to utility-owned procured resource provisions. Accordingly, standard offer contracts under the Prospective QF Program shall specifically provide for the pass through of future “regulatory legal risk conditions” (e.g., Greenhouse Gas costs, regulatory compliance required capital additions, Electric Reliability Organization costs.

13. The CAISO must accept QF power as a must-take resource; QFs greater than one MW should only be required to comply with CAISO Tariff provisions to the extent the provisions are directly applicable to QF operations.

14. The utility should continue to serve as the scheduling coordinator for QFs,

however, the QF should have the option of serving as its own scheduling coordinator. In such a case, the QF has the option of purchasing these services from the utility at cost.

15. The prospective QF Program contract options should be extended to QFs that are, or were, on contract extensions set forth in D.02-08-071, D.03-12-062, D.04-01-050, and D.05-12-009.

16. The prospective QF program should include an LRAC firm pricing option that reflects CAC/EPUC's recommended values for capacity and a fixed heat rate of 7,500 Btu/kWh and an established O&M adder for the term of the contract.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) shall revise their short-run avoided cost (SRAC) calculations in conformance with the discussion, findings, and conclusions set forth in this decision as summarized in Table 1. The pricing determinations in this decision will not become effective until final standard offer contracts are available to QFs as discussed in this decision.

~~2. PG&E, SDG&E, and SCE shall file and serve their respective compliance draft Qualifying Facility contracts as directed by this decision within 45 days of the effective date of this decision. Parties may file comments on the draft contracts 21 days thereafter~~.

2. If implementation issues remain unresolved in the final decision the Assigned Commissioner shall convene a workshop to begin no later than 14 days from the final decision. The implementation workshop is to be strictly monitored process with the Assigned Commissioner presiding over issues identified and left unresolved by the final decision.

3. Parties shall file proposed standard offer contract forms no later than June 7, 2007. Reply comments on the proposals may be filed no later than June 21, 2007. If

there are unresolved issues pertaining to the standard offers those issues may be addressed at the post-final decision workshop on implementation issues.

4. The Assigned Commissioner's Ruling on any outstanding implementation or standard offer contract issues shall be issued no later than 21 days after the conclusion of the Assigned Commissioner's workshop following the final decision.

5. ~~3.~~ Rulemaking (R.) 04-04-003 and R.04-04-25 are closed. Filings from the Mohave application, A.02-05-046 ordered by D.04-12-016 to be filed in these proceedings are no longer to be filed. Instead, D.04-12-016 compliance reports are to be submitted to the ALJ and Energy Division and served on the service list for A.02-05-046. The service list for A.02-05-046 will now be a special service list in R.06-02-013. Filings from the 2006 Update phase of R.04-04-025 ordered in D.06-06-063 should be filed in R.06-04-010. The monthly SRAC postings ordered in this decision shall be submitted to the Energy Division and posted on each Investor Owned Utilities' web site.

CERTIFICATE OF SERVICE

I, Karen Terranova hereby certify that I have on this date caused the attached **Opening Comments of the Cogeneration Association of California and the Energy Producers & Users Coalition on the Proposed Decision of Administrative Law Judge Halligan** in R.04-04-003/R04-04-025 to be served to all known parties by either United States mail or electronic mail, to each party named in the official attached service list obtained from the Commission's website, attached hereto, and pursuant to the Commission's Rules of Practice and Procedure.

Dated May 25, 2007 at San Francisco, California.

Karen Terranova

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Karen Terranova

ALAN NOGEE
UNION OF CONCERNED SCIENTISTS
2 BRATTLE SQUARE
CAMBRIDGE, MA 02238
anogee@ucsusa.org

ROGER BERLINER
BERLINER LAW PLLC
1747 PENNSYLVANIA AVE. N.W., STE 825
WASHINGTON, DC 20006
roger@berlinerlawpllc.com

LISA M. DECKER
CONSTELLATION ENERGY GROUP, INC.
111 MARKET PLACE, SUITE 500
BALTIMORE, MD 21202
lisa.decker@constellation.com

JAMES ROSS
RCS INC.
500 CHESTERFIELD CENTER, SUITE 320
CHESTERFIELD, MO 63017
jimross@r-c-s-inc.com

TOM SKUPNJAK
CPG ENERGY
5211 BIRCH GLEN
RICHMOND, TX 77469
toms@i-cpg.com

PAUL M. SEBY
MCKENNA LONG & ALDRIDGE LLP
1875 LAWRENCE STREET, SUITE 200
DENVER, CO 80202
pseby@mckennalong.com

TIMOTHY R. ODIL
MCKENNA LONG & ALDRIDGE LLP
1875 LAWRENCE STREET, SUITE 200
DENVER, CO 80202
todil@mckennalong.com

MAUREEN LENNON
CALIFORNIA COGENERATION COUNCIL
595 EAST COLORADO BLVD., SUITE 623
PASADENA, CA 91101
maureen@lennonassociates.com

DANIEL W. DOUGLASS
DOUGLASS & LIDDELL
21700 OXNARD STREET, SUITE 1030
WOODLAND HILLS, CA 91367-8102
douglass@energyattorney.com

BERJ K. PARSEGHIAN
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
berj.parseghian@sce.com

JAMES WOODRUFF
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
woodrujb@sce.com

JANET COMBS
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
janet.combs@sce.com

MICHAEL A. BACKSTROM
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
michael.backstrom@sce.com

DANIEL A. KING
SEMPRA ENERGY RESOURCES
101 ASH STREET
SAN DIEGO, CA 92101
daking@sempra.com

GEORGETTA J. BAKER
SAN DIEGO GAS & ELECTRIC/SOCAL GAS
101 ASH STREET, HQ 13
SAN DIEGO, CA 92101
gbaker@sempra.com

CRYSTAL NEEDHAM
EDISON MISSION ENERGY
18101 VON KARMAN AVE., STE 1700
IRVINE, DC 92612-1046
cneedham@edisonmission.com

W. PHILLIP REESE
CALIFORNIA BIOMASS ENERGY ALLIANCE, LLC
PO BOX 8
SOMIS, CA 93066
phil@reesechambers.com

MICHEL PETER FLORIO
THE UTILITY REFORM NETWORK (TURN)
711 VAN NESS AVENUE, SUITE 350
SAN FRANCISCO, CA 94102
mflorio@turn.org

Karen P. Paull
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
kpp@cpuc.ca.gov

Marion Peleo
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
map@cpuc.ca.gov

DEVRA WANG
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER STREET, 20TH FLOOR
SAN FRANCISCO, CA 94104
dwang@nrdc.org

EVELYN KAHL
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO, CA 94104
ek@a-klaw.com

EDWARD V. KURZ
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET
SAN FRANCISCO, CA 94105
evk1@pge.com

SHIRLEY WOO
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, B30A
SAN FRANCISCO, CA 94105
saw0@pge.com

ANN G. GRIMALDI
MCKENNA LONG & ALDRIDGE LLP
101 CALIFORNIA STREET, 41ST FLOOR
SAN FRANCISCO, CA 94111
agrimaldi@mckennalong.com

KAREN BOWEN
WINSTON & STRAWN LLP
101 CALIFORNIA STREET
SAN FRANCISCO, CA 94111
kbowen@winston.com

JOSEPH M. KARP
WINSTON & STRAWN LLP
101 CALIFORNIA STREET
SAN FRANCISCO, CA 94111-5802
jkarp@winston.com

JEFFREY P. GRAY
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
jeffgray@dwt.com

ARTHUR L. HAUBENSTOCK
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120
alhj@pge.com

MARY A. GANDESBERY
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120
magq@pge.com

SARA STECK MYERS
LAW OFFICES OF SARA STECK MYERS
122 - 28TH AVENUE
SAN FRANCISCO, CA 94121
ssmyers@att.net

ALAN PURVES
CALIFORNIA LANDFILL GAS COALITION
5717 BRISA STREET
LIVERMORE, CA 94550
purves@grsllc.net

RICK NOGER
PRAXAIR PLAINFIELD, INC.
2678 BISHOP DRIVE
SAN RAMON, CA 94583
rick_noger@praxair.com

WILLIAM H. BOOTH
LAW OFFICES OF WILLIAM H. BOOTH
1500 NEWELL AVENUE, 5TH FLOOR
WALNUT CREEK, CA 94596
wbooth@booth-law.com

ANDREW HOERNER
REDEFINING PROGRESS
1904 FRANKLIN STREET, 6TH FLOOR
OAKLAND, CA 94612
hoerner@redefiningprogress.org

ERIC LARSEN
RCM DIGESTERS
PO BOX 4716
BERKELEY, CA 94704
elarsen@rcmdigesters.com

GREGG MORRIS
GREEN POWER INSTITUTE
2039 SHATTUCK AVE., SUITE 402
BERKELEY, CA 94704
gmorris@emf.net

JOHN GALLOWAY
UNION OF CONCERNED SCIENTISTS
2397 SHATTUCK AVENUE, SUITE 203
BERKELEY, CA 94704
jgalloway@ucsusa.org

NANCY RADER
CALIFORNIA WIND ENERGY ASSOCIATION
2560 NINTH STREET, SUITE 213A
BERKELEY, CA 94710
nrader@calwea.org

TOM BEACH
CROSSBORDER ENERGY
2560 NINTH STREET, SUITE 316
BERKELEY, CA 94710
tomb@crossborderenergy.com

PATRICK MCDONNELL
AGLAND ENERGY SERVICES, INC.
2000 NICASIO VALLEY RD.
NICASIO, CA 94946
pcmcdonnell@earthlink.net

BARBARA GEORGE
WOMEN'S ENERGY MATTERS
PO BOX 548
FAIRFAX, CA 94978
wem@igc.org

MICHAEL E. BOYD
CALIFORNIANS FOR RENEWABLE ENERGY, INC.
5439 SOQUEL DRIVE
SOQUEL, CA 95073
michaelboyd@sbcglobal.net

JOY A. WARREN
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO, CA 95354
joyw@mid.org

BARBARA R. BARKOVICH
BARKOVICH & YAP, INC.
44810 ROSEWOOD TERRACE
MENDOCINO, CA 95460
brbarkovich@earthlink.net

WILLIAM B. MARCUS
JBS ENERGY, INC.
311 D STREET, SUITE A
WEST SACRAMENTO, CA 95608
bill@jbsenergy.com.

RICHARD D. ELY
DAVIS HYDRO
27264 MEADOWBROOK DRIVE
DAVIS, CA 95618
hydro@davis.com

GRANT A. ROSENBLUM
CALIFORNIA INDEPENDENT SYSTEM OPERATOR
151 BLUE RAVINE ROAD
FOLSOM, CA 95630
grosenblum@caiso.com

STACIE FORD
CALIFORNIA ISO
151 BLUE RAVINE ROAD
FOLSOM, CA 95630
sford@caiso.com

ANDREW B. BROWN
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO, CA 95814
abb@eslawfirm.com

DOUGLAS K. KERNER
ELLISON, SCHNEIDER & HARRIS, LLP
2015 H STREET
SACRAMENTO, CA 95814
dkk@eslawfirm.com

ANN L. TROWBRIDGE
DAY CARTER MURPHY LLC
3620 AMERICAN RIVER DRIVE, SUITE 205
SACRAMENTO, CA 95864
atrowbridge@daycartermurphy.com

MICHAEL ALCANTAR
ALCANTAR & KAHL, LLP
1300 SW FIFTH AVENUE, SUITE 1750
PORTLAND, OR 97201
mpa@a-klaw.com

CARLO ZORZOLI
ENEL NORTH AMERICA, INC.
1 TECH DRIVE, SUITE 220
ANDOVER, MA 1810
carlo.zorzoli@enel.it

DANIEL V. GULINO
RIDGEWOOD POWER MANAGEMENT, LLC
947 LINWOOD AVENUE
RIDGEWOOD, NJ 7450
dgulino@ridgewoodpower.com

WILLIAM P. SHORT
RIDGEWOOD POWER MANAGEMENT, LLC
947 LINWOOD AVENUE
RIDGEWOOD, NJ 7450
bshort@ridgewoodpower.com

RICHARD M. ESTEVES
SESCO, INC.
77 YACHT CLUB DRIVE, SUITE 1000
LAKE HOPATCONG, NJ 7849
sesco@optonline.net

CAROL A. SMOOTS
PERKINS COIE LLP
607 FOURTEENTH STREET, NW, SUITE 800
WASHINGTON, DC 20005
csmoots@perkinscoie.com

JOSEPH B. WILLIAMS
MCDERMOTT WILL & EMERGY LLP
600 THIRTEENTH STREET, N.W.
WASHINGTON, DC 20005-3096
jbwilliams@mwe.com

MICHAEL A. YUFFEE
MCDERMOTT WILL & EMERY LLP
600 THIRTEENTH STREET, N.W.
WASHINGTON, DC 20005-3096
myuffee@mwe.com

ANAN H. SOKKER
CHADBOURNE & PARKE LLP
1200 NEW HAMPSHIRE AVE. NW
WASHINGTON, DC 20036

ROBERT SHAPIRO
CHADBOURNE & PARKE LLP
1200 NEW HAMPSHIRE AVE. NW
WASHINGTON, DC 20036
rshapiro@chadbourne.com

TANDY MCMANNES
SOLAR THERMAL ELECTRIC ALLIANCE
101 OCEAN BLUFFS BLVD.APT.504
JUPITER, FL 33477-7362

RALPH E. DENNIS
FELLON-MCCORD & ASSOCIATES
9960 CORPORATE CAMPUS DRIVE, STE 2000
LOUISVILLE, KY 40223
ralph.dennis@constellation.com

DOUGLAS MCFARLAN
MIDWEST GENERATION EME
440 SOUTH LASALLE ST., SUITE 3500
CHICAGO, IL 60605
dmcfarlan@mwgen.com

BRIAN HANEY
UTILITY SYSTEM EFFICIENCIES, INC.
1000 BOURBON ST., 341
NEW ORLEANS, LA 70116
brianhaney@useconsulting.com

JANET DOYLE
KRAMER JUNCTION COMPANY
1636 AJAX LANE
EVERGREEN, CO 80439
jheckdoyle@aol.com

DAVID SAUL
SOLEL, INC.
701 NORTH GREEN VALLEY PKY, STE 200
HENDERSON, NV 89074
david.saul@solel.com

CHRISTOPHER HILEN
SIERRA PACIFIC POWER COMPANY
6100 NEIL ROAD
RENO, NV 89511
chilen@sppc.com

RASHA PRINCE
SAN DIEGO GAS & ELECTRIC
555 WEST 5TH STREET, GT14D6
LOS ANGELES, CA 90013
rprince@semprautilities.com

HOWARD W. CHOY
LOS ANGELES COUNTY ISD, FACILITIES OPERA
1100 NORTH EASTERN AVENUE
LOS ANGELES, CA 90063
hchoy@isd.co.la.ca.us

DAVID L. HUARD
MANATT, PHELPS & PHILLIPS, LLP
11355 WEST OLYMPIC BOULEVARD
LOS ANGELES, CA 90064
dhuard@manatt.com

RANDALL W. KEEN
MANATT, PHLEPS & PHILLIPS, LLP
11355 WEST OLYMPICS BLVD.
LOS ANGELES, CA 90064
pucservice@manatt.com

CURTIS KEBLER
GOLDMAN, SACHS & CO.
2121 AVENUE OF THE STARS
LOS ANGELES, CA 90067
curtis.kebler@gs.com

SAM HITZ
CALIFORNIA CLIMATE ACTION REGISTRY
515 S. FLOWER STREET, STE 1640
LOS ANGELES, CA 90071
sam@climateregistry.org

MICHAEL J. GIBBS
ICF CONSULTING
14724 VENTURA BLVD., NO. 1001
SHERMAN OAKS, CA 91403
mgibbs@icfconsulting.com

CASE ADMINISTRATION
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
case.admin@sce.com

ERIC J. ISKEN
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
j.eric.isken@sce.com

GARY L. ALLEN
SOUTHERN CALIFORNIA EDISON
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
gary.allen@sce.com

LAURA GENAO
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
laura.genao@sce.com

LIZBETH MCDANNEL
2244 WALNUT GROVE AVE., QUAD 4D
ROSEMEAD, CA 91770
lizbeth.mcdannel@sce.com

TORY S. WEBER
SOUTHERN CALIFORNIA EDISON COMPANY
2131 WALNUT GROVE AVENUE
ROSEMEAD, CA 91770
tory.weber@sce.com

JOY C. YAMAGATA
SAN DIEGO GAS & ELECTRIC/SOCALGAS
8330 CENTURY PARK COURT
SAN DIEGO, CA 91910
jyamagata@semprautilities.com

DON WOOD
PACIFIC ENERGY POLICY CENTER
4539 LEE AVENUE
LA MESA, CA 91941
dwood8@cox.net

TIM HEMIG
NRG ENERGY, INC.
1819 ASTON AVENUE, SUITE 105
CARLSBAD, CA 92008
tim.hemig@nrgenergy.com

KEITH W. MELVILLE
SEMPRA ENERGY
101 ASH STREET
SAN DIEGO, CA 92101
kmelville@sempra.com

GREG BASS
SEMPRA ENERGY SOLUTIONS
101 ASH STREET. HQ09
SAN DIEGO, CA 92101-3017
gbass@semprasolutions.com

DONALD C. LIDDELL, P.C.
DOUGLASS & LIDDELL
2928 2ND AVENUE
SAN DIEGO, CA 92103
liddell@energyattorney.com

SCOTT J. ANDERS
UNIVERSITY OF SAN DIEGO SCHOOL OF LAW
5998 ALCALA PARK
SAN DIEGO, CA 92110
scottanders@sandiego.edu

WILLIAM E. POWERS
POWERS ENGINEERING
4452 PARK BLVD., STE. 209
SAN DIEGO, CA 92116
bpowers@powersengineering.com

CENTRAL FILES
SAN DIEGO GAS & ELECTRIC
8330 CENTURY PARK COURT, CP31E
SAN DIEGO, CA 92123
centralfiles@semprautilities.com

CHUCK MANZUK
SAN DIEGO GAS AND ELECTRIC COMPANY
8330 CENTURY PARK CT
SAN DIEGO, CA 92123
cmanzuk@semprautilities.com

IRENE M. STILLINGS
CALIFORNIA CENTER FOR SUSTAINABLE ENERGY
8690 BALBOA AVE., STE. 100
SAN DIEGO, CA 92123
irene.stillings@energycenter.org

JOSEPH KLOBERDANZ
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT
SAN DIEGO, CA 92123
jkloberdanz@semprautilities.com

DESPINA PAPAPOSTOLOU
SAN DIEGO GAS AND ELECTRIC COMPANY
8330 CENTURY PARK COURT-CP32H
SAN DIEGO, CA 92123-1530
dpapapostolou@semprautilities.com

JOHN W. LESLIE
LUCE, FORWARD, HAMILTON & SCRIPPS, LLP
11988 EL CAMINO REAL, SUITE 200
SAN DIEGO, CA 92130
jleslie@luce.com

LAWRENCE KOSTRZEWA
EDISON MISSION ENERGY
18101 VON KARMAN AVE., STE 1700
IRVINE, CA 92612-1046
lkostrzewa@edisonmission.com

PHILIP HERRINGTON
EDISON MISSION ENERGY
18101 VON KARMAN AVENUE, STE 1700
IRVINE, CA 92612-1046
pherrington@edisonmission.com

JIM MCARTHUR
ELK HILLS POWER, LLC
4026 SKYLINE ROAD
TUPMAN, CA 93276
jmcarthur@elkhills.com

BARRY LOVELL
BERRY PETROLEUM COMPANY
5201 TRUXTUN AVE., SUITE 300
BAKERSFIED, CA 93309
bjl@bry.com

JANIS C. PEPPER
CLEAN POWER MARKETS, INC.
PO BOX 3206
LOS ALTOS, CA 94024
pepper@cleanpowermarkets.com

CHRIS KING
CALIFORNIA CONSUMER EMPOWERMENT
ONE TWIN DOLPHIN DRIVE
REDWOOD CITY, CA 94065
chris@emeter.com

MARC D. JOSEPH
ADAMS, BROADWELL, JOSEPH & CARDOZO
601 GATEWAY BLVD., STE. 1000
SOUTH SAN FRANCISCO, CA 94080
mdjoseph@adamsbroadwell.com

STEVEN A. LEFTON
APTECH ENGINEERING SERVICES INC.
PO BOX 3440
SUNNYVALE, CA 94089-3440
slefton@aptecheng.com

DIANE I. FELLMAN
LAW OFFICE OF DIANE I. FELLMAN
234 VAN NESS AVENUE
SAN FRANCISCO, CA 94102
diane_fellman@fpl.com

MATTHEW FREEDMAN
THE UTILITY REFORM NETWORK
711 VAN NESS AVENUE, SUITE 350
SAN FRANCISCO, CA 94102
freedman@turn.org

Noel Obiora
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
nao@cpuc.ca.gov

KAREN TERRANOVA
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, STE 2200
SAN FRANCISCO, CA 94104
filings@a-klaw.com

NORA SHERIFF
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO, CA 94104
nes@a-klaw.com

ROD AOKI
ALCANTAR & KAHL, LLP
120 MONTGOMERY STREET, SUITE 2200
SAN FRANCISCO, CA 94104
rsa@a-klaw.com

CHRIS ANN DICKERSON, PHD
FREEMAN, SULLIVAN & CO.
100 SPEAR ST., 17/F
SAN FRANCISCO, CA 94105
dickerson06@fscgroup.com

ED LUCHA
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MAIL CODE B9A
SAN FRANCISCO, CA 94105
ell5@pge.com

MARC KOLB
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, B918
SAN FRANCISCO, CA 94105
mekd@pge.com

MARK R. HUFFMAN
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET
SAN FRANCISCO, CA 94105
mrh2@pge.com

TOM JARMAN
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE STREET, MAIL CODE B9A
SAN FRANCISCO, CA 94105-1814
taj8@pge.com

CALIFORNIA ENERGY MARKETS
517-B POTRERO AVE
SAN FRANCISCO, CA 94110
cem@newsdata.com

BRIAN T. CRAGG
GOODIN MACBRIDE SQUERI RITCHIE & DAY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO, CA 94111
bcragg@goodinmacbride.com

JANINE L. SCANCARELLI
FOLGER, LEVIN & KAHN, LLP
275 BATTERY STREET, 23RD FLOOR
SAN FRANCISCO, CA 94111
jscancarelli@flk.com

REN ORENS
ENERGY AND ENVIRONMENTAL ECONOMICS
353 SACRAMENTO ST., STE 1700
SAN FRANCISCO, CA 94111
ren@ethree.com

ROBERT B. GEX
DAVIS WRIGHT TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
bobgex@dwt.com

STEVEN F. GREENWALD
DAVIS WRIGHT TREMAINE, LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO, CA 94111-6533
stevegreenwald@dwt.com

CHARLES R. MIDDLEKAUFF
PACIFIC GAS & ELECTRIC COMPANY LAW DEPT.
PO BOX 7442
SAN FRANCISCO, CA 94120
ermd@pge.com

LAW DEPARTMENT FILE ROOM
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120-7442
cpuccases@pge.com

MARGARET D. BROWN
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 7442
SAN FRANCISCO, CA 94120-7442
mdbk@pge.com

EDWARD C. REMEDIOS
33 TOLEDO WAY
SAN FRANCISCO, CA 94123-2108
ecrem@ix.netcom.com

LYNNE BROWN
CALIFORNIANS FOR RENEWABLE ENERGY, INC.
24 HARBOR ROAD
SAN FRANCISCO, CA 94124
l_brown369@yahoo.com

MAURICE CAMPBELL
CALIFORNIANS FOR RENEWABLE ENERGY, INC.
1100 BRUSSELS ST.
SAN FRANCISCO, CA 94134
mecsoft@pacbell.net

GRACE LIVINGSTON-NUNLEY
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000 MAIL CODE B9A
SAN FRANCISCO, CA 94177
gxl2@pge.com

KATHERINE RYZHAYA
PACIFIC GAS & ELECTRIC COMPANY
PO BOX 770000
SAN FRANCISCO, CA 94177
karp@pge.com

NINA BUBNOVA
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, MAIL CODE B9A
SAN FRANCISCO, CA 94177
nbb2@pge.com

VALERIE J. WINN
PACIFIC GAS AND ELECTRIC COMPANY
PO BOX 770000, B9A
SAN FRANCISCO, CA 94177-0001
vjw3@pge.com

KENNETH E. ABREU
853 OVERLOOK COURT
SAN MATEO, CA 94403
k.abreu@sbcglobal.net

MARK J. SMITH
FPL ENERGY
3195 DANVILLE BLVD, STE 201
ALAMO, CA 94507
mark_j_smith@fpl.com

MARK HARRER
56 ST. TIMOTHY CT.
DANVILLE, CA 94526
mhharrer@sbcglobal.net

ANDREW J. VAN HORN
VAN HORN CONSULTING
12 LIND COURT
ORINDA, CA 94563
andy.vanhorn@vhcenergy.com

ALEXANDRE B. MAKLER
CALPINE CORPORATION
3875 HOPYARD ROAD, SUITE 345
PLEASANTON, CA 94588
alexm@calpine.com

AVIS KOWALEWSKI
CALPINE CORPORATION
3875 HOPYARD ROAD, SUITE 345
PLEASANTON, CA 94588
kowalewskia@calpine.com

PETER W. HANSCHEN
MORRISON & FOERSTER, LLP
101 YGNACIO VALLEY ROAD, SUITE 450
WALNUT CREEK, CA 94596
phanschen@mofo.com

J.A. SAVAGE
CALIFORNIA ENERGY CIRCUIT
3006 SHEFFIELD AVE.
OAKLAND, CA 94602
editorial@californiaenergycircuit.net

MRW & ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND, CA 94612
mrw@mrwassoc.com

DAVID HOWARTH
MRW & ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND, CA 94612
mrw@mrwassoc.com

WILLIAM A. MONSEN
MRW & ASSOCIATES, INC.
1814 FRANKLIN STREET, SUITE 720
OAKLAND, CA 94612
mrw@mrwassoc.com

REED V. SCHMIDT
BARTLE WELLS ASSOCIATES
1889 ALCATRAZ AVENUE
BERKELEY, CA 94703-2714
rschmidt@bartlewells.com

JANICE LIN
STRATEGEN CONSULTING LLC
146 VICENTE ROAD
BERKELEY, CA 94705
janice@strategenconsulting.com

CHRISTOPHER J. MAYER
MODESTO IRRIGATION DISTRICT
PO BOX 4060
MODESTO, CA 95352-4060
chrism@mid.org

ROBERT SARVEY
501 W. GRANTLINE RD
TRACY, CA 95376
sarveybob@aol.com

JOHN C. GABRIELLI
GABRIELLI LAW OFFICE
430 D STREET
DAVIS, CA 95616
gabriellilaw@sbcglobal.net

RICHARD MCCANN
M.CUBED
2655 PORTAGE BAY ROAD, SUITE 3
DAVIS, CA 95616
rmccann@umich.edu

SHAWN SMALLWOOD, PH.D.
3108 FINCH ST.
DAVIS, CA 95616-0176
puma@davis.com

DAVID MORSE
1411 W, COVELL BLVD., SUITE 106-292
DAVIS, CA 95616-5934
demorse@omsoft.com

BRIAN THEAKER
WILLIAMS POWER COMPANY
3161 KEN DEREK LANE
PLACERVILLE, CA 95667
brian.theaker@williams.com

STEVEN A. GREENBERG
DISTRIBUTED ENERGY STRATEGIES
4100 ORCHARD CANYON LANE
VACAVILLE, CA 95688
steveng@destrategies.com

DOUG DAVIE
DAVIE CONSULTING, LLC
3390 BEATTY DRIVE
EL DORADO HILLS, CA 95762
dougdpucmail@yahoo.com

DAVID REYNOLDS
ASPEN SYSTEMS CORPORATION
5802 BALFOR ROAD
ROCKLIN, CA 95765
dreynolds@aspensys.com

DAN L. CARROLL
DOWNEY BRAND, LLP
555 CAPITOL MALL, 10TH FLOOR
SACRAMENTO, CA 95814
dcarroll@downeybrand.com

EDWARD J TIEDEMANN
KRONICK MOSKOVITZ TIEDEMANN AND GIRARD
400 CAPITOL MALL
SACRAMENTO, CA 95814
etiedemann@kmtg.com

KEVIN WOODRUFF
WOODRUFF EXPERT SERVICES, INC.
1100 K STREET, SUITE 204
SACRAMENTO, CA 95814
kdw@woodruff-expert-services.com

WILLIAM W. WESTERFIELD III
ELLISON, SCHNEIDER & HARRIS LLP
2015 H STREET
SACRAMENTO, CA 95814
www@eslawfirm.com

VIKKI WOOD
SACRAMENTO MUNICIPAL UTILITY DISTRICT
6301 S STREET, MS A204
SACRAMENTO, CA 95817-1899
vwood@smud.org

RICHARD LAUCKHART
HENWOOD ENERGY SERVICES, INC.
2379 GATEWAY OAKS DRIVE, SUITE 200
SACRAMENTO, CA 95833
rlauckhart@henwoodenergy.com

E. JESUS ARREDONDO
NRG ENERGY, INC.
3741 GRESHAM LANE
SACRAMENTO, CA 95835
jesus.arredondo@nrgenergy.com

KAREN LINDH
LINDH & ASSOCIATES
7909 WALERGA ROAD, NO. 112, PMB 119
ANTELOPE, CA 95843
karen@klindh.com

PATRICK HOLLEY
COVANTA ENERGY CORPORATION
2829 CHILDRESS DR.
ANDERSON, CA 96007-3563
pholley@covantaenergy.com

ANNE FALCON
EES CONSULTING, INC.
570 KIRKLAND AVE
KIRLAND, WA 98033
rfp@eesconsulting.com

DONALD SCHOENBECK
RCS, INC.
900 WASHINGTON STREET, SUITE 780
VANCOUVER, WA 98660
dws@r-c-s-inc.com

Peter Lai
CALIF PUBLIC UTILITIES COMMISSION
320 WEST 4TH STREET SUITE 500
LOS ANGELES, CA 90013
ppl@cpuc.ca.gov

Amy C. Yip-Kikugawa
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
ayk@cpuc.ca.gov

Charlyn A. Hook
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
chh@cpuc.ca.gov

Donna J. Hines
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
djh@cpuc.ca.gov

Jerry Oh
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
joh@cpuc.ca.gov

Julie Halligan
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
jmh@cpuc.ca.gov

Matthew Deal
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
mjd@cpuc.ca.gov

Merideth Sterkel
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
mts@cpuc.ca.gov

Mikhail Haramati
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
mkh@cpuc.ca.gov

Robert Kinosian
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
gig@cpuc.ca.gov

Robert L. Strauss
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
rls@cpuc.ca.gov

Sepideh Khosrowjah
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
skh@cpuc.ca.gov

Shannon Eddy
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
sed@cpuc.ca.gov

Steve Linsey
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
car@cpuc.ca.gov

Sudheer Gokhale
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
skg@cpuc.ca.gov

Susannah Churchill
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
sc1@cpuc.ca.gov

Terrie D. Prosper
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
tdp@cpuc.ca.gov

Theresa Cho
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
tcx@cpuc.ca.gov

Thomas Roberts
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
tcr@cpuc.ca.gov

Traci Bone
CALIF PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3214
tbo@cpuc.ca.gov

SNULLER PRICE
ENERGY AND ENVIRONMENTAL ECONOMICS
101 MONTGOMERY, SUITE 1600
SAN FRANCISCO, CA 94104
snuller@ethree.com

ANDREW ULMER
CALIFORNIA DEPARTMENT OF WATER RESOURCES
1416 NINTH STREET
SACRAMENTO, CA 95814
aulmer@water.ca.gov

BRADLEY MEISTER
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-26
SACRAMENTO, CA 95814
bmeister@energy.state.ca.us

Don Schultz
CALIF PUBLIC UTILITIES COMMISSION
770 L STREET, SUITE 1050
SACRAMENTO, CA 95814
dks@cpuc.ca.gov

KRIS G. CHISHOLM
CALIFORNIA ELECTRICITY OVERSIGHT BOARD
770 L STREET, SUITE 1250
SACRAMENTO, CA 95814
kris.chisholm@eob.ca.gov

MICHAEL JASKE
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-500
SACRAMENTO, CA 95814
mjaske@energy.state.ca.us

Wade McCartney
CALIF PUBLIC UTILITIES COMMISSION
770 L STREET, SUITE 1050
SACRAMENTO, CA 95814
wsm@cpuc.ca.gov

MARY ANN MILLER
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS 20
SACRAMENTO, CA 96814-5512
mmiller@energy.state.ca.us

RON WETHERALL
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET MS 20
SACRAMENTO, CA 96814-5512
rwethera@energy.state.ca.us